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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007 (Filed February 11, 2016)

ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON STAFF PROPOSAL ON PROCESS FOR INTEGRATED RESOURCE PLANNING

This ruling seeks comment from interested parties on the attached Staff Proposal titled "Proposal for Implementing Integrated Resource Planning at the CPUC: An Energy Division Staff Proposal" (Staff Proposal). Substantial portions of this proposal have already been shared with parties during numerous webinars and workshops over the past several months, but the Staff Proposal is now being entered into the formal record of the proceeding via this ruling.

Parties who wish to provide formal comments in response to this ruling must file and serve them no later than June 14, 2017. Reply comments must be filed and served by no later than June 26, 2017.

1. Background

Commission staff has been circulating informal staff working papers, conducting webinars and workshops, and seeking informal party comments over the course of the past several months. Following is a list of informal activities that were conducted by Commission staff in preparation for the release of the attachments to this ruling. Commission staff and I appreciate parties' willingness to provide informal comments, which have helped inform, shape, and improve the Staff Proposal attached to this ruling.

Original Staff Concept Paper

- August 11, 2016: Staff Concept Paper circulated for informal comment
- August 24, 2016: Webinar conducted on staff concept paper
- August 31, 2016: Parties provided pre-workshop informal comments
- September 26, 2016: Workshop conducted

Analytical Framework

- September 30, 2016: Staff Analytical Framework discussed at September 26, 2016 workshop circulated for informal comment
- October 14, 2016: Parties provided informal comments

Scenario Development

- October 24, 2016: Staff Proposed Approach to Scenario Development circulated for informal comment
- October 27, 2016 and November 10, 2016: Webinars conducted to discuss scenario development
- November 3, 2016: Parties provided informal comments
- December 16, 2016: Half-day workshop conducted
- December 27, 2016: Staff issued questions related to the December 16 workshop discussions
- January 13, 2017: Parties provided informal comments

Modeling Advisory Group

- October 5, 2016: Staff circulated draft charter for the Modeling Advisory Group for informal comment

- October 14, 2016: Parties provided informal comments
- October 20, 2016, November 3, 2016, November 17, 2016 and January 12, 2017: Webinars conducted
- December 16, 2016: Half-day workshop conducted

Load serving entity (LSE)-specific greenhouse gas (GHG) emissions reduction targets

- November 15, 2016: Staff white paper on implementing GHG planning targets for Integrated Resource Planning (IRP) circulated
- November 30, 2016: Parties provided informal comments
- December 7, 2016: Parties provided informal reply comments

Electric Sector GHG targets

- February 10, 2017: California Public Utilities Commission (CPUC) and California Energy Commission (CEC) Joint Staff Paper: Options for Setting GHG Planning Targets for Integrated Resource Planning and Apportioning Targets among Publicly Owned Utilities and Load Serving Entities, circulated for informal comment
- February 21, 2017: Parties provided pre-workshop informal comments
- February 23, 2017: Joint CEC/CPUC workshop on setting GHG targets conducted
- March 9, 2017: Parties provided informal reply comments

In addition to the above informal activities, Assigned Commissioner Randolph and I issued a ruling December 21, 2016, which sought comment on other aspects of the integrated resource planning process, including the appropriate treatment of disadvantaged communities in the IRP process, among other items. Numerous parties filed comments in response to that ruling on

February 17, 2017, and reply comments on February 27, 2017. Those comments and replies also informed numerous elements of the Staff Proposal attached to this ruling.

2. Request for Formal Comments

Attached to this ruling is a Staff Proposal which also contains numerous appendices, citations, and links to additional items posted on the Commission's web site.

To guide parties' and the Commission's review of these materials, this ruling requests that all parties, to the extent they wish, respond in their comments to the following questions about the major recommendations contained in the attached Staff Proposal.

Questions

1. Guiding principles. Are the guiding principles for IRP articulated in Chapter 1 of the Staff Proposal adequate and appropriate for Commission policy purposes? What changes would you recommend and why?
2. Disadvantaged communities objectives. Are the objectives for addressing disadvantaged communities in IRP in Chapter 1 of the Staff Proposal adequate and appropriate in light of the statutory requirements? What changes would you recommend and why? Please make reference to the specific objectives and statutory requirements in your response.
3. Overall IRP process. Comment on the overall IRP process proposed in Chapter 2 of the Staff Proposal, beginning with the California Air Resources Board (CARB) establishing greenhouse gas planning targets for the electricity sector and ending with the Commission procurement and policy implementation. What changes would you recommend and why?
4. 2017-2018 IRP process. Do you support the Staff Proposal's characterization of the purpose and

outcomes of the first round of IRP in 2017-2018? Why or why not?

5. Electric sector 2030 GHG emissions targets. Do you support using the CARB Scoping Plan as the starting point for setting the electric sector GHG emissions target or range for 2030? Why or why not?

6. LSE-specific GHG emissions targets.

   a. Do you support dividing electric sector responsibility between publicly-owned utilities (POUs) and LSEs regulated by the Commission, as suggested in the Staff Proposal? Why or why not?

   b. Is further differentiation of GHG emissions responsibility by LSE based on an overall sectoral marginal GHG abatement cost curve or planning price reasonable? Why or why not?

   c. What challenges might individual LSEs encounter in preparing their portfolios based on a marginal GHG abatement planning price? How might those challenges be overcome?

   d. If you recommend a different approach to setting LSE-specific GHG emissions targets, please describe it in detail.

7. Modeling in 2017-2018.

   a. Do you support use of the RESOLVE modeling approach for development of a Reference System Plan in 2017-2018? Why or why not?

   b. If you prefer an alternative approach, describe it in detail.

8. GHG emissions scenarios to be modeled.

   a. Are the four GHG emissions levels for the electric sector recommended to be analyzed by staff the appropriate ones? Why or why not?

   b. What alternative targets do you recommend and why?

9. <u>Modeling Assumptions.</u> Do you have any specific changes to recommend to the modeling assumptions detailed in Chapter 4 and Appendix B of the Staff Proposal and the associated spreadsheet Scenario Tool? What are they and why? Indicate a publicly-available source of your recommended assumptions.

10. <u>Modeling outputs and metrics.</u> Are the modeling outputs and metrics in Chapter 4 of the Staff Proposal reasonable? What changes would you suggest and why? Be as specific as possible about how to quantify your recommended metrics.

11. <u>Sensitivities</u>. Are the sensitivities defined in Chapter 4 of the Staff Proposal reasonable? What changes would you suggest and why?

12. <u>Futures</u>. Are the alternative futures proposed to be modeled in Chapter 4 of the Staff Proposal the appropriate ones? What changes would you suggest and why?

13. <u>Costs</u>. Is the cost analysis summarized in the Staff Proposal appropriate and sufficient for the Commission to assess tradeoffs among alternative futures and choose the appropriate level of GHG emissions reductions in the electric sector by 2030 for which to plan? Explain.

14. <u>Risks.</u>

    a. Are there any other risks or criteria that should be considered in the portfolio analysis described in the Staff Proposal?

    b. How should the risks associated with not achieving the State goals listed in Table 4.4 of the Staff Proposal be defined and quantified? Propose an appropriate and feasible methodology and explain how the cost of reducing each risk can be quantified.

15. <u>Disadvantaged communities definition</u>.

    a. Is it appropriate to use communities scoring at or above the 75th percentage in the California Environmental

Protection Agency's CalEnviroScreen 3.0 Tool as the definition of "disadvantaged" for IRP analysis purposes? Why or why not?

b. Are there any other analyses that could better inform the development of metrics to account for the costs and benefits of prioritizing disadvantaged communities?

16. <u>Demand-side resources.</u>

a. Is the treatment of these resources in the staff's recommended approach reasonable? What changes would you suggest and why?

b. What additional information, other than modeling, might materially affect these resources? Provide specific sources of publicly available information, what question(s) the additional information would help address, and why you think the information should be used.

c. What market, regulatory, or other barriers could prevent or impede an optimal level of procurement for each resource area and type of LSE, and what solutions would you recommend to address the identified barriers? Explain your answer clearly and provide quantitative support using publicly available information wherever feasible.

17. <u>Supply-side resources.</u>

a. Is the treatment of these resources in the staff's recommended approach reasonable? What changes would you suggest and why?

b. What additional information, other than modeling, might materially affect these resources? Provide specific sources of publicly available information, what question(s) the additional information would help address, and why you think the information should be used.

c. What market, regulatory, or other barriers could prevent or impede an optimal level of procurement for each resource area and type of LSE, and what solutions would you recommend to address the identified barriers? Explain your answer clearly and provide quantitative support using publicly available information wherever feasible.

18. Short-term investments, actions, or procurement. Has staff identified the correct areas for analysis to determine the need for short-term investment or procurement activities, including: bulk storage, out of state wind, and geothermal resources? What changes or additions would you recommend and why?

19. Transportation electrification.

    a. Do you support the Staff Proposal's approach to characterizing transportation electrification and the uncertainties and impacts associated with it? Explain.

    b. What tools and/or data could be used to assess how electric vehicle deployment could maximize benefits to disadvantaged communities?

20. Reference System Plan development.

    a. What methodology should staff use to develop a recommendation for the portfolio to include in the Reference System Plan?

    b. If you recommend a scorecard-style approach, what weight should be given to each state goal in Table 4.4 of the Staff Proposal?

    c. Are there any additional criteria, apart from the goals listed in Table 4.4 of the Staff Proposal, that staff should also include? If so, why?

    d. Are there any additional questions or studies that staff should address in the Reference System Plan? If so, describe each question or study and explain why you think it should be included, considering the limited time and resources available.

21. LSE filing process. Do you support the approach to LSE IRP filing outlined in Chapter 5 of the Staff Proposal? Why or why not?

22. General LSE filing requirements.

    a. Are there any additional general requirements that the Commission should require LSEs to include in their IRPs?

    b. Are any of the general requirements proposed by staff infeasible to provide? If so, explain what barriers make providing the information infeasible, what the risks of not requiring the information might be for both bundled and unbundled customers, and how that risk could be mitigated in another, more feasible way.

23. Technical LSE filing requirements.

    a. Are there any additional technical requirements that the Commission should require LSEs to include in their LSE Plans? Describe in detail.

    b. Are there any staff-recommended technical requirements that should be omitted or consolidated? Specify.

    c. Are any of the technical requirements proposed by staff infeasible to provide? If so, explain the barriers that make providing the information infeasible, the risks of not requiring the information (for bundled and unbundled customers) and how the risks could be mitigated in another, more feasible way.

24. LSE IRP Filing Template. Describe any changes you recommend to the Staff-recommended template in Appendix C and explain why.

25. Standard and Alternative IRPs. Do you support the staff proposal for standard and alternative IRP filings? What changes would you suggest, either to the overall approach or to the specific requirements for each, and why?

26. For individual LSEs:

  a. Do you support the staff recommendation for the type of IRP you should file? Why or why not?

  b. If you have an alternative recommendation, please describe it in detail.

27. Individual LSE load determination. How should the Commission determine what load to assign to each LSE for IRP filing purposes? Describe your preferred method in detail, such that it can be readily reproduced using publicly available information.

28. For individual LSEs:

  a. What load should you be assigned for 2017-2018 IRP purposes?

  b. Describe in detail the methodology associated with your proposed load obligation.

29. Marginal GHG abatement cost/planning price: Is it appropriate and feasible for the Commission to use the results of the IRP analysis to inform the inputs for certain cost-effectiveness analysis, such as in the Integrated Distributed Energy Resource proceeding evaluation of the societal cost test for demand-side resources? Why or why not?

30. Relationship between IRPs and procurement.

  a. Describe your reaction to the Staff Proposal's characterization of how IRP development and approval will lead to actual resource procurement in the next few years.

  b. Are there any alternative approaches to IRP-based procurement that the Commission should consider? If so, describe the approach in detail and explain which specific problems it would address with reference to the statutory requirements for IRP, while not conflicting with other Commission non-IRP statutory requirements.

c. What existing rules should the Commission consider studying to improve the ability of the IRP process to achieve its goals (e.g., Renewable Energy Credit banks, Renewables Portfolio Standard content categories, etc.)? What approaches or methodologies should the Commission consider using to study the costs and benefits of your proposals?

d. How should the Commission ensure that LSEs comply with their approved IRPs? Describe your preferred approach in detail, with reference to the IRP statutory requirements.

31. <u>Relationship between IRPs and bundled procurement plans.</u>

a. Does the Staff Proposal appropriately characterize the relationship? What changes would you recommend to the approach and why?

b. What interactions between the IRP process and the bundled procurement practices and policies should be considered in future IRP cycles? Identify specific bundled plan requirements that may need to be changed to facilitate coordination with IRP in the future.

32. <u>Disadvantaged communities impacts in procurement.</u>

a. Do you support the Staff Proposal's approach to assessment of the impacts of procurement on disadvantaged communities? What changes would you recommend and why?

b. What specific quantitative and/or qualitative showings should LSEs be required to provide to demonstrate how disadvantaged communities were considered in the development of their IRPs?

c. How should the Commission utilize the information provided by the LSEs to assess the impacts of procurement on disadvantaged communities?

33. Cost allocation and cost recovery.

a. Is the Staff Proposal approach to these issues workable? What changes would you recommend and why?

b. How important is it for the Commission to allocate responsibility for deficiencies in the aggregate portfolio (of all LSE plans) to individual LSEs?

c. How should the Commission address the situation where one LSE's IRP is identifiably the cause of a gap in meeting the Reference System Plan GHG target for the electric sector (e.g., if one LSE does not appropriately factor the GHG Planning Price into its IRP)?

d. How should the Commission assign responsibility for procurement of system or flexibility resources when an overall deficiency is identified?

34. Alignment of IRP process with other Commission resource proceedings.

a. Are there obvious opportunities for alignment across Commission proceedings that the staff should consider in developing a process alignment workplan?

b. What would be the benefits to coordinating proceedings to align based on these opportunities?

c. Identify any barriers to coordination.

35. Preferred System Plan. Is the Staff Proposal's recommendation to utilize a Commission-approved Preferred System Plan as the basis for input into the IEPR and TPP processes appropriate and workable? What changes would you recommend and why?

36. Alignment with CEC's Integrated Energy Policy Report (IEPR) and California Independent System Operator's (CAISO's) Transmission Planning Process (TPP).

a. Do you support the Staff Proposal approach to coordination with the IEPR and TPP processes? What changes would you recommend and why?

b. Are there specific outputs from the IRP process that should be included in California's long-term planning processes that were not previously outputs from the long-term procurement planning process? Describe the outputs and the benefits of including them.

c. Are there previous outputs from long-term procurement planning that are not anticipated to be included in IRP but which may be necessary? Describe the outputs and the benefits of including them.

37. Regional Planning. How should the IRP process and analysis take into account the potential for CAISO regionalization?

Parties filing and serving comments are requested to organize their comments in the same order as and with reference to the questions above, even if a party chooses not to answer all questions. Parties are also free to comment on any other aspects of the Staff Proposal not specifically included in the questions above; those additional comments should follow the responses to the numerical questions. There is no page limit on the length of comments or reply comments.

Parties may file and serve comments by no later than June 14, 2017. Reply comments may be filed and served by no later than June 26, 2017.

3. Schedule of Activities

To facilitate parties' understanding of the attached Staff Proposal, Commission staff plan to host an informational webinar, designed for parties to ask clarifying questions, on May 24, 2017. Further details about the webinar will be posted to the Commission's Daily Calendar and shared with the service list of this proceeding.

Following receipt of parties' comments on the Staff Proposal, Commission staff plans to finalize and release a draft of the Reference System Plan described in the Staff Proposal. This proposed Reference System Plan will be released for comment by a ruling similar to this one.

The proposed Reference System Plan will include a summary of the modeling platform details and documentation, a summary of the candidate portfolios evaluated, a recommended portfolio, and all analytical results of the modeling. A formal workshop will follow the release of the proposed Reference System Plan, and parties will be invited to submit formal comments and reply comments.

All of the above materials will form the basis of a proposed decision to be brought before the Commission in Fall 2017 that will give guidance and set out requirements for all LSEs who are required to file IRPs.

These activities are summarized in the table below, with expected timeframes.

Activity	**Expected Timing**
Public webinar on IRP Staff Proposal	May 24, 2017
Comments due on Staff Proposal	June 14, 2017
Reply comments due on Staff Proposal	June 26, 2017
Ruling to issue proposed Reference System Plan and associated analysis	July 2017
Workshop(s) on proposed Reference System Plan	July and August 2017 (details to follow)
Comments due on proposed Reference System Plan	August 2017
Reply comments due on proposed Reference System Plan	August or September 2017
Modeling Advisory Group meeting to discuss modeling changes needed in 2018	September 2017
Proposed Decision on IRP filing requirements and Reference System Plan	Fall 2017

Activity	Expected Timing
IRP filings by individual LSEs	First Quarter 2018
LSE IRPs evaluated by Commission	Second and Third Quarter 2018
LSE IRPs adopted or modified by Commission	End of 2018
IRP guidance transmitted to CAISO and CEC for TPP and IEPR purposes	Early 2019

IT IS RULED that:

1. The Staff Proposal attached to this ruling is hereby entered into the formal record of this proceeding.
2. Parties may file and serve comments in response to the Staff Proposal attached to this ruling by no later than June 14, 2017. Parties should respond to the questions in Section 2 of this ruling with reference to specific question numbers. Comments on any and all other aspects of any of the Staff Proposal attachment may follow.
3. Parties may file and serve reply comments by no later than June 26, 2017.

Dated May 16, 2017, at San Francisco, California.

/s/ JULIE A. FITCH

Julie A. Fitch
Administrative Law Judge

Proposal for Implementing Integrated Resource Planning at the CPUC

An Energy Division Staff Proposal

California Public Utilities Commission

May 17, 2017

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Abbreviations

A&S	Assumptions and Scenarios
AAEE	Additional Achievable Energy Efficiency
BAA	Balancing Authority Area
BTM	Behind-the-Meter
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CPUC	California Public Utilities Commission
DAC	Disadvantaged Community
DER	Distributed Energy Resources
DR	Demand Response
DRP	Distribution Resources Plan
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
EPIC	Electric Program Investment Charge
ERRA	Energy Resource Recovery Account
ESP	Electric Service Provider
EV	Electric Vehicle
GHG	Greenhouse Gas
GWh	Gigawatt hour
IDER	Integrated Distributed Energy Resources
IEPR	Integrated Energy Policy Report
IOU	Investor Owned Utility
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
IRP 2017-18	The first cycle the CPUC's new IRP process
LCA	Life Cycle Assessment
LSE	Load Serving Entity
LTPP	Long-Term Procurement Plan
MJU	Multi-jurisdictional Utility
MMTCO2e	Million Metric Tons of Carbon Dioxide Equivalent
MW	Megawatt
MWh	Megawatt hour
N/A	Not Applicable
OIR	Order Instituting Rulemaking
OOS	Out-of-state
PCIA	Power Charge Indifference Adjustment
P&G Study	Energy Efficiency Potential and Goals Study
PG&E	Pacific Gas and Electric Company
POU	Publicly-owned utility
Pub. Util. Code §	California Public Utilities Code Section
PV	Photovoltaic
REC	Renewable Energy Credit
RETI	Renewable Energy Transmission Initiative
RFO	Request for Offers
RPS	Renewables Portfolio Standard
SB	Senate Bill

SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SMJU	Small and Multi-jurisdictional Utility
TBD	To Be Determined
TEPPC	Transmission Expansion Planning Policy Committee
TOU	Time-of-Use
TPP	Transmission Planning Process
WECC	Western Electricity Coordinating Council
ZEV	Zero Emissions Vehicle
ZNE	Zero Net Energy

Definitions

Alternative LSE Plan: type of integrated resource plan that an LSE may be eligible to file if its assigned load forecast is < 700 GWh in any of the first five years of the IRP planning horizon.

Approve (an LSE Plan): the CPUC's obligation to approve an LSE's integrated resource plan derives from Public Utilities Code Section 454.52(b)(2) and the procurement planning process described in Public Utilities Code Section 454.5, in addition to the CPUC obligation to ensure safe and reliable service at just and reasonable rates under Public Utilities Code Section 451.

Certify (a CCA Plan): Public Utilities Code 454.52(b)(3) requires the CPUC to certify the integrated resource plans of CCAs. "Certify" requires a formal act of the Commission to determine that the CCA's Plan complies with the requirements of the statute and the process established via Public Utilities Code 454.51(a). In addition, the Commission must review the CCA Plans to determine any potential impacts on public utility bundled customers under Public Utilities Code Sections 451 and 454, among others.

Community Choice Aggregator: a governmental entity formed by a city or county to procure electricity for its residents, businesses, and municipal facilities

Electric Service Provider: an entity that offers electric service to a retail or end-use customer, but which does not fall within the definition of an electrical corporation under Public Utilities Code Section 218

Filing entity: an entity required by statute to file an integrated resource plan with CPUC

Future: a set of assumptions about future conditions, such as load or gas prices

Sensitivity: a future in which only one assumption differs from a specific comparison case

GHG Planning Price: the system-wide marginal GHG abatement cost associated with achieving the electric sector 2030 GHG planning target

Governing board: the authority responsible for regulating rates of a CCA

IRP: integrated resource planning

IRP process: integrated resource planning process; the repeating cycle through which integrated resource plans are prepared, submitted, and reviewed by the CPUC

Long term: 10 or more years (unless otherwise specified)

LSE: an electrical corporation, electric service provider, or community choice aggregator

LSE Plan: an LSE's integrated resource plan; the full set of documents and information submitted by an LSE to CPUC as part of the IRP process

LSE-preferred portfolio: the portfolio preferred by an LSE as the most suitable to its own needs; submitted to CPUC for review as one feature of the overall IRP

Non-modeled costs: embedded fixed costs in today's energy system (e.g., existing distribution revenue requirement, existing transmission revenue requirement, and EE program cost)

Portfolio: a set of supply and/or demand resources with certain attributes that together serve a particular level of load

Preferred System Action Plan: the set of short-term actions and activities necessary to implement the Preferred System Portfolio; part of the Preferred System Plan

Preferred System Plan: aggregate of integrated resource plans submitted by LSEs regulated by CPUC that is informed by the Reference System Plan and achieves same state goals as the Reference Plan

Preferred System Portfolio: the multi-LSE portfolio identified by LSEs, reviewed by Energy Division, and approved by the CPUC as most responsive to statutory requirements per Pub. Util. Code 454.51; part of the Preferred System Plan

Reference System Action Plan: the set of short-term actions and activities necessary to implement the Reference System Portfolio; part of the Reference System Plan

Reference System Plan: Energy Division's integrated resource plan that includes an optimal portfolio (Reference System Portfolio) of future resources for serving load in the CAISO balancing authority area and meeting multiple state goals, including meeting GHG reduction and reliability targets at least cost

Reference System Portfolio: the multi-LSE portfolio identified by Energy Division and approved by the CPUC as most responsive to statutory requirements per Pub. Util. Code 454.51; part of the Reference System Plan

Scenario: a portfolio together with a set of assumptions about future conditions

Scoping Plan: California Air Resource Board's 2017 Climate Change Scoping Plan Update

Short term: 1 to 3 years (unless otherwise specified)

Staff: CPUC Energy Division staff (unless otherwise specified)

Standard LSE Plan: type of integrated resource plan that an LSE will be required to file if its assigned load forecast is ≥ 700 GWh in any of the first five years of the IRP planning horizon.

Executive Summary

Senate Bill (SB) 350, known as the Clean Energy and Pollution Reduction Act of 2015, introduced integrated resource planning (IRP) as the statewide approach to electric resource planning in California. In Public Utilities Code Sections 454.51 and 454.52, SB 350 requires the IRP process to meet California's greenhouse gas (GHG) emissions reduction targets for the electric sector, consistent with the statewide goal of achieving a 40 percent reduction in GHG emissions below 1990 levels by 2030, while maintaining reliability, minimizing bill impacts, and prioritizing air quality benefits in disadvantaged communities.

The CPUC's IRP process[1] has the potential to identify the best mix of supply- and demand-side resources to reduce GHG emissions and ensure reliability while meeting the state's other policy goals. Ideally, this "integrated" approach to resource planning will help California transition away from its history of resource-specific procurement requirements and mandates. Through its IRP process, the CPUC has an opportunity to identify optimal solutions that might not otherwise be found, and to guide resource investment decisions across all types of load-serving entities (LSEs) and resource programs.

IRP is not a new concept, yet the IRP process in California will be unlike any other. IRP is typically the domain of a single, vertically integrated utility, but the CPUC's IRP process will cover multiple types of LSEs, large and small, with different load shapes, resource types, and planning and procurement practices. Energy resource planning in California also involves multiple state agencies—the CPUC, California Energy Commission (CEC), and California Air Resources Board (CARB)—and the California Independent System Operator (CAISO). The state uses a combination of markets and mandates to achieve its policy goals, meaning the CPUC's IRP process must balance the need to ensure that LSEs meet program requirements, while providing LSEs sufficient flexibility to take advantage of low-cost solutions provided by the market.

With these unique circumstances in mind, staff proposes an iterative IRP process that:

- divides responsibility between the CPUC and the entities it regulates;
- highlights the cost impacts of actions that address different state and local policies and goals; and
- facilitates a two-way information exchange with other planning activities at CARB, CEC, and the CAISO.

Under the proposed IRP process, the CPUC will lead an optimization modeling effort to identify a portfolio and an action plan that together best address the state's multiple policy goals. Individual LSEs will use elements of the CPUC-adopted portfolio to generate their own preferred portfolios, customized to meet their individual needs. This division of labor enables the consideration of system-level resources

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[1] The CEC is responsible for the development of IRP guidelines for POUs. For more information see: http://www.energy.ca.gov/sb350/IRPs/

that have the potential to benefit all ratepayers, as well as local or regional solutions that address specific needs, values and concerns. The high-level steps of the proposed IRP process are summarized as follows:

1. CARB establishes GHG planning targets for the IRP process in coordination with the CPUC and CEC.
2. The CPUC conducts modeling to identify optimal combinations of resources under different assumptions about the future; selects a portfolio of future resources; defines an action plan that best achieves multiple state goals (the CPUC-adopted portfolio and action plan comprise the "Reference System Plan"); and provides specific guidance to LSEs on what LSE Plans filed with the CPUC must include.
3. The Reference System Plan forms the basis for subsequent modeling or other analytical work by LSEs to develop their respective LSE Plans. LSEs develop and file their own LSE Plans, which include each LSE's preferred portfolio and recommended set of short-term actions.
4. The CPUC reviews all LSE Plans individually and then aggregates the LSE-preferred portfolios into a single portfolio of resources to evaluate it for consistency with state goals, including GHG emissions reduction and reliability. The Commission votes on the aggregate portfolio and corresponding short-term actions to serve as the "Preferred System Plan," formally replacing the Reference System Plan for that IRP cycle. Similar to the Reference System Plan, the Preferred System Plan includes a set of short-term actions and activities (Preferred System Action Plan) necessary to implement the Preferred System Portfolio.
5. The CPUC determines whether to authorize new procurement, program funding, or tariff changes to meet the requirements of the Preferred System Plan.

Considering the California electricity sector's unique position and the complexity of transitioning away from the existing resource planning paradigm, staff proposes that the IRP proceeding's overarching goal in 2017-18 be to establish the essential groundwork and structure for IRP, as defined in the steps listed above, and to move through the entire process once. Efforts should be focused on generating the optimal portfolio to meet SB 350 goals, establishing a formal process for filing and reviewing LSE Plans, and defining the relationship between IRP and procurement with respect to other resource programs and proceedings at the CPUC.

Specifically, staff recommends that this first IRP cycle generate information regarding the optimal resource mix needed to achieve the state's GHG reduction goals, evaluate the need for short-term procurement to ensure reliability, and evaluate long lead-time investment opportunities that may be necessary to meet GHG reduction goals.

The defining aspects of IRP 2017-18 as they appear within the proposed IRP process are as follows:

- **Coordination between CARB, CPUC, and CEC in establishing GHG planning targets for the electric sector and individual LSEs and POUs**. Staff recommends using the results of the 2017 Climate Change Scoping Plan Update (Scoping Plan) as a starting point to inform the electric sector GHG emissions reductions target for IRP. For the purposes of dividing the electric sector target between the CPUC's and CEC's respective IRP processes, staff plans to use a bottom-up approach based on CARB's draft methodology for the 2021-2030 allowance allocation to electric distribution utilities under the state's Cap-and-Trade program. Staff proposes identifying a system-wide marginal GHG abatement cost (i.e., the "GHG Planning Price") as a proxy for achieving the electric sector target in IRP 2017-18, and requiring LSEs to prepare their Plans using that price.

- **Developing and operationalizing a model to generate an optimal portfolio of resources over a 20-year planning horizon (2018-2038) that achieves SB 350 goals (i.e., Reference System Plan)**. In IRP 2017-18 staff will use a capacity expansion model called RESOLVE to produce portfolios of resources that are least-cost under a variety of different possible future conditions. Staff will recommend a single portfolio to use in future planning and procurement activities, propose near-term actions associated with that portfolio, and develop IRP filing guidance for individual LSEs (together comprising the "Reference System Plan").
- **Establishing expectations for what LSEs should include in their IRP filings, how their Plans will be evaluated this cycle, and how they will be aggregated into the Preferred System Plan**. Each LSE will file its Plan as an application to the CPUC, and all IRP applications will be consolidated into a single proceeding for both individual and joint evaluation. Staff proposes that the CPUC organize IRP filing requirements based on the load forecast assigned to each LSE over the IRP planning horizon, with two categories of LSE Plans: Standard and Alternative. Standard Plans will be required for LSEs whose assigned load forecast is ≥ 700 GWh in any of the first five years of the IRP planning horizon, and other LSEs may be eligible to file an Alternative Plan. Minimum requirements will be established for content and data format for each category of Plan. For Alternative Plans, staff proposes a simplified review process; for Standard Plans, staff proposes to review each LSE Plan both individually and in aggregate. Whether the plans pass individual review and aggregate review will determine the appropriate action by the CPUC.
- **Defining expectations for IRP procurement and cost recovery based on the Reference System Plan and the Preferred System Plan, both in IRP 2017-18 and in future cycles**. Staff acknowledges that the IRP-based procurement approach is likely to change over time based on program feedback and lessons learned. For the IRP 2017-18 cycle, staff proposes the following:
  - The IRP process will generate information about the optimal portfolio, develop a GHG Planning Price, and evaluate procurement needs under circumstances that include, but are not limited to, the following:
    - If long-term (10 or more years) reliability needs that require new investment are clearly identified, or if unexpected short-term (1 to 3 years) reliability needs arise, the IRP proceeding will contemplate authorizing or directing procurement to satisfy those needs.
    - A new track or proceeding may be opened to further explore any capital intensive, long-lead time resources (e.g., out-of-state wind, large-scale pumped hydro, etc.) that IRP analysis indicates is likely to be beneficial.

    - If the GHG reduction target adopted for the electric sector requires new investment in zero carbon energy, IRP will consider recommending accelerating the date by which a 50% RPS must be achieved.
    - If the quantity of short duration storage in the adopted portfolio differs from what regulated LSEs are currently required and/or authorized to procure, IRP will consider recommending changing the storage procurement target (higher or lower).
    - If the quantity of distributed energy resources in the adopted portfolio, including energy efficiency, demand response, and behind-the-meter solar PV differs from the quantities anticipated to result from existing Commission policies, IRP will consider recommending changes to the affected program rules, funding levels, and/or goals.
  - The IRP process will provide a marginal GHG abatement value (a GHG Planning Price) for use in the Integrated Distributed Energy Resources proceeding (R.14-10-003) and Energy Efficiency proceeding (R.13-11-005).
  - The IRP process will be coordinated with the RPS proceeding to produce a common resource valuation methodology that can be applied across all resources, establishing a clear link between planning and procurement.

- **Specifying expectations for alignment between IRP and other resource programs and proceedings at the CPUC, as well as coordination among the CPUC, CEC, CARB, and CAISO**. Staff articulates the need for alignment between IRP and other resource programs and proceedings at the CPUC (i.e., "internal process alignment"), as well as coordination among the CPUC, CEC, CARB, and CAISO (i.e., "external process alignment").
  - Internal process alignment**:** Staff describes its workplan for aligning IRP with other procurement-related proceedings as operating along three paths: identifying opportunities for process alignment; establishing a formal internal process for vetting IRP inputs and outputs; and establishing formal, Commissioner-level engagement practices via the "Engagement Plan for Process Alignment," which includes a vision, goals, and timeline for process alignment.
  - External process alignment**:** Staff also describes recommendations for how IRP 2017-18 may be aligned with other statewide and regional planning processes, including the 2019 CEC Integrated Energy Policy Report, the 2018-19 and 2019-20 CAISO Transmission Planning Processes, and Western Electricity Coordinating Council activities.

Staff expects IRP 2017-18 to demonstrate the feasibility of the proposed process and set the course for future rounds of IRP. If procurement needs are demonstrated by the LSEs in their Plans, this proceeding will evaluate what decisions the Commission should make to meet those needs. The lessons learned from this first cycle may be incorporated into a revised, multi-year IRP process, beginning in 2019 and operating over a two-year cycle. Party feedback on the recommendations in this Staff Proposal will inform the development of the Reference System Plan and LSE filing requirements, and will help staff further refine its recommendations to the Commission for procurement, cost recovery, and requirements related to disadvantaged communities in the IRP 2017-18 cycle.

Chapter 1: Introduction

Background on SB 350 and IRP in California

Senate Bill (SB) 350, known as the Clean Energy and Pollution Reduction Act of 2015, introduced integrated resource planning (IRP) as the statewide approach to electric resource planning in California. In Public Utilities Code Sections 454.51 and 454.52 (see Appendix A), SB 350 requires the IRP process to meet California's greenhouse gas (GHG) emissions reduction targets for the electric sector, consistent with the statewide goal of achieving a 40 percent reduction in GHG emissions below 1990 levels by 2030, while maintaining reliability, minimizing bill impacts, and minimizing localized air pollutants and other greenhouse gas emissions with early priority on disadvantaged communities.

The IRP process has the potential to identify the best mix of supply- and demand-side resources to reduce GHG emissions and ensure reliability while meeting the state's other policy goals. Ideally, this "integrated" approach to resource planning will help California transition away from its history of relying on resource-specific procurement requirements and mandates.

The regulatory landscape for California's electric sector is broadly defined by a few characteristics:

- Electricity customers are served by a diverse array of retail providers, including publicly-owned utilities (POUs) who report their activities to the California Energy Commission (CEC), in addition to other types of load serving entities (LSEs) under CPUC oversight, including investor-owned utilities (IOUs), community choice aggregators (CCAs), electric service providers (ESPs), and electric cooperatives.
- The state has enacted numerous resource-specific policy mandates for energy efficiency (EE), demand response (DR), renewable energy (e.g., the Renewables Portfolio Standard (RPS)), energy storage, and alternative-fuel vehicles, among other resources, which are being achieved through a combination of markets, programs, planning efforts, policy mandates, and infrastructure investments.
- California's electric resource planning processes are highly fragmented: with few exceptions, each resource type has distinct planning and procurement activities, and each LSE performs resource planning independently.

SB 350 is a recognition by California's leadership that isolated planning processes are unlikely to result in an optimal mix of energy resources across the state, hampering the state's ability to achieve its 2030 policy goals in a least-cost manner. Through the IRP process, the CPUC has an opportunity to identify optimal solutions that might not otherwise be found and to guide resource investment decisions across all types of LSEs and resource programs.

Purpose

The purpose of this Staff Proposal is to make recommendations on guidance for the CPUC IRP process and contents, and specifically to:

- Propose a revised set of guiding principles for developing an IRP process at the CPUC.
- Specify the high-level components of the proposed CPUC IRP process.
- Solicit party feedback on staff proposals for key components of the IRP 2017-18 cycle, including:
    - Setting GHG emission reduction planning targets for individual LSEs.
    - Development of the Reference System Plan, including which scenarios staff will model in 2017, the rationale for choosing those scenarios, the method staff will use in selecting a recommended portfolio, and the assumptions used in modeling.
    - Filing requirements for LSEs and expectations for how LSE Plans will be evaluated and aggregated into the Preferred System Plan.
    - IRP procurement and cost recovery based on the Reference System Plan, LSE Plans, and Preferred System Plan, including how to determine whether new procurement authorization, program funding, or tariff changes are necessary.
    - Requirements related to disadvantaged communities (DACs).
    - Process alignment between IRP and other resource programs and proceedings at the CPUC, as well as coordination among the CPUC, CEC, CARB, and CAISO.

Similar to the IRP Concept Paper released by staff in August 2016, this document is accompanied by a formal ruling that contains specific questions for parties to answer. Parties should number their answers to match the specific question being addressed. Party feedback on this document will inform the development of the Reference System Plan and LSE filing requirements, and will help staff further refine its recommendations to the Commission for procurement, cost recovery, and requirements related to DACs in the IRP 2017-18 cycle.

Document Organization

This document is organized into seven chapters and several appendixes:

- **Chapter 1** explains the purpose and goals of the Staff Proposal, provides background on SB 350 and IRP implementation activities at the CPUC-staff level, and lists the guiding principles for developing the CPUC IRP process.
- **Chapter 2** specifies the high-level components of the IRP process and outlines staff's goals for the 2017-18 cycle of IRP.
- **Chapter 3** describes the interagency coordination between CARB, CPUC, and CEC in establishing GHG planning targets for the IRP process and staff's recommendation for setting GHG planning targets for individual LSEs.
- **Chapter 4** provides a description of the RESOLVE model and how it will be used in IRP. It also covers the scenarios that Energy Division staff proposes to model as part of the IRP process, the rationale for choosing those scenarios, the method staff proposes to use in selecting a

recommended portfolio, and what kind of information will be included in the Reference System Plan.

- **Chapter 5** covers staff's proposal for what information should be included in LSE Plans when they are submitted to CPUC and how those Plans will be evaluated.
- **Chapter 6** describes staff's recommended approach to procurement in the IRP 2017-18 cycle and how procurement may evolve in future iterations of the IRP process, including the link between procurement and cost recovery.
- **Chapter 7** describes staff's proposal for process alignment with other programs and proceedings in IRP 2017-18, how process alignment should evolve over the next several IRP cycles, and how this evolution should be managed.
- **Appendix A** contains the full text of SB 350 Sections 454.51 and 454.52. **Appendix B** provides tables of the major assumptions for each sensitivity and future to be studied in IRP modeling. Appendix B also includes the DRAFT RESOLVE Inputs and Assumptions document describing how the input data for IRP 2017-18 were developed. (For more detailed information about assumptions, see also the "Scenario Tool" workbook available on the CPUC website.[2)] **Appendix C** provides a template for LSEs to use when filing a "Standard Plan." **Appendix D** contains a description of the data files staff will provide to document the Reference System Portfolio.

IRP Development to Date

The CPUC opened the IRP proceeding (R. 16-02-007) in February 2016 to accomplish several objectives, chief of which was to develop a process for the filing of integrated resource plans. CPUC staff has since generated numerous work products and held several workshops and webinars to facilitate public participation and solicit party feedback on recommendations for the IRP process. Such efforts and engagements have been essential to the development of content and recommendations in this Staff Proposal. Below is a summary of CPUC staff activities to-date on IRP process development.[2]

- June 2016: Workshop Introducing IRP in California
- August 2016: IRP Concept Paper[3] to solicit informal party feedback and inform the development of the IRP Staff Proposal
- September 2016: Workshop on Options for Implementing IRP
- October – December 2016: Six webinars and a workshop on various technical components of the IRP process, in particular modeling and scenario development

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[2] All IRP-related staff products are available for download at: http://www.cpuc.ca.gov/General.aspx?id=6442451195

[3] Available at: http://www.cpuc.ca.gov/General.aspx?id=12400

- November 2016: Staff White Paper on Implementing GHG Planning Targets in IRP[4]
- February 2017: A CPUC and CEC Staff Discussion Document on Options for Setting GHG Planning Targets for IRP and Apportioning Targets among POUs and LSEs,[5] and a Joint Agency (CPUC, CEC, and CARB) Workshop on 2030 GHG Emission Reduction Targets for IRP

IRP staff has been actively coordinating with other staff within the Energy Division on aligning IRP efforts and goals with those of other resource programs and proceedings. In addition, staff has held numerous meetings with CARB, CEC, and CAISO staff on IRP-related process alignment issues, including IRP alignment with the Integrated Energy Policy Report (IEPR) and Transmission Planning Process (TPP). IRP staff has also participated in Energy Division efforts toward the formation of the joint CEC-CPUC SB 350 DAC Advisory Group,[6] which will review and provide advice on clean energy programs initiated by the CPUC and the CEC.[7]

Guiding Principles

The CPUC Staff Concept Paper on IRP (August 2016) put forth a set of principles intended to guide the CPUC's implementation and administration of IRP. Rather than to simply restate the Public Utilities Code, the Guiding Principles were designed to serve as a foundation upon which the basic components of the IRP process could be established, and also as criteria for evaluating one proposal against another. Parties were asked to identify any inconsistencies between the Guiding Principles and statutory, CPUC, or other requirements, and to explain how those inconsistencies should be resolved. Parties were also asked to identify any additional guiding principles that should be included.

The Guiding Principles below were revised in response to informal party comment on the IRP Staff Concept Paper and during the Workshop on Options for Implementing the CPUC IRP Process held on September 26, 2016. Two new Guiding Principles have been added. In addition, staff has outlined a set of objectives to address requirements related to disadvantaged communities in IRP. Parties are encouraged to identify any aspects of this Staff Proposal that deviate from the following Guiding Principles and DAC-related objectives, and to offer detailed recommendations on how those deviations should be addressed.

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[4] Available at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451662
[5] Available at: http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/Energy Programs/ElectPowerProcurementGeneration/LTPP/2017/GHGOptionsPaper.pdf
[6] The DAC advisory group is expected to review and provide advice on programs proposed to achieve clean energy and pollution reduction and to determine whether those proposed programs will be effective and useful in disadvantaged communities.
[7] A joint-workshop is expected to be held to engage stakeholders and inform next steps taken by both agencies in the formation of this group.

Revised Guiding Principles

1. The structure and design of the IRP process should reduce greenhouse gas emissions and ensure electric grid reliability while meeting the state's other policy goals in a cost-effective manner.
2. The IRP process should be as transparent and accessible as possible to provide meaningful public participation for parties, members of the public, and customers of each LSE.
3. The IRP process should provide clear market signals for existing and new resources to facilitate sufficient, timely, and cost-effective technology and infrastructure investments.
4. Filing entities should have the flexibility to respond to changes in technology, electric system needs, and market conditions.
5. The CPUC's resource-specific proceedings should be coordinated with or consolidated within IRP planning activities to the maximum extent feasible.
6. The IRP process should align with related planning processes of other state and federal agencies and entities, while avoiding any redundancy or conflict with other state policies and programs.

New Guiding Principles

7. The IRP process should recognize that filing entities have different governing bodies, procurement processes, and statutory obligations, while also ensuring that the content and format of their Plans are consistent and actionable despite those differences.
8. Any costs resulting from procurement directed by the IRP process should be allocated in a fair and equitable manner to LSE customers, and there should be no cost shifting between customers of different LSEs.

Objectives for Addressing Disadvantaged Communities in IRP

In order to guide actions taken to prioritize the reduction of localized air pollutants and other greenhouse gas emissions in DACs, pursuant to PUC 454.52(a)(1)(H), staff has outlined the following IRP-related DAC objectives:

1. The actions resulting from the IRP process should reduce GHG emissions, provide air quality co-benefits, and avoid adverse air quality impacts in DACs in a cost-effective manner.
2. The IRP process will assist with the coordination of disadvantaged community issues across proceedings; however, different proceedings should be prepared to scope in issues related to DACs.
3. The IRP process will coordinate with sister agencies (CARB, CalEPA, and local air districts) to track, measure, and assess the impact of the CAISO system on air pollution.
4. Due to the varying nature of jurisdictional oversight, the Commission will decide which entities are best positioned to take actions and make investments that prioritize DACs. Large IOUs are expected to meet the SB 350 requirements related to DACs; however, these requirements may vary for other LSEs.

5. The IRP process will be used to quantify the costs and benefits of DAC-related policies relevant to IRP.

Chapter 2: IRP Process

Chapter Summary

Staff proposes an iterative IRP process that achieves the state's multiple policy goals by balancing a system-wide perspective with a consideration of the unique circumstances of each individual LSE.

- The CPUC will lead the effort to represent the system-wide perspective by identifying a portfolio of new resources that together meet policy goals.
- Individual LSEs will then use the Commission-adopted Reference System Portfolio as a benchmark for generating their own preferred portfolios.
- The LSE portfolios will be submitted to the CPUC, where they will be aggregated into a new system-wide portfolio and evaluated for compliance with policy goals.
- The new, aggregate portfolio will be adopted by the Commission as the Preferred System Portfolio and will drive procurement and program activity across multiple supply and demand resources.
- The IRP process will repeat every two years.

Staff proposes that IRP 2017-18 will establish and demonstrate the feasibility of the proposed process. In this round, the Preferred System Portfolio will generally serve to provide non-binding information to individual resource proceedings, which will continue to be responsible for planning and implementing their respective programs. In future cycles, staff hopes that IRP will absorb the planning function across resources while individual proceedings will continue to be responsible for program implementation and procurement.

Proposed CPUC IRP Process

IRP is not a new concept, yet the IRP process in California will be unlike any other. IRP is typically the domain of a single, vertically integrated utility, but as explained in **Chapter 1**, the CPUC's IRP process will cover multiple types of LSEs, large and small, with different types of loads, resources, and planning and procurement practices. Energy resource planning in California also involves multiple state agencies—CPUC, CEC, and CARB—and the CAISO, each of which has distinct authority and/or tools at its disposal. The state also uses a combination of markets and mandates to achieve its policy goals, meaning that the CPUC's IRP process must balance the need to ensure regulated entities meet program requirements, while providing the LSEs sufficient flexibility to take advantage of low-cost solutions provided by the market but not identified in the IRP process.

With these unique circumstances in mind, staff proposes an iterative IRP process that:

- divides responsibility between the CPUC and the entities it regulates;
- highlights the cost impacts of actions that address different state policies and goals; and
- facilitates a two-way information exchange with other planning activities at CARB, CEC, and the CAISO.

Under the proposed approach, the CPUC will leverage Energy Division's new Energy Resource Modeling group to lead an optimization modeling effort to identify a portfolio and an action plan that together best address the state's multiple policy goals. Individual LSEs will use elements of that portfolio to generate their own preferred portfolios, customized to meet their individual needs. This division of labor enables the consideration of system-level resources that have the potential to benefit all ratepayers, as well as local or regional solutions that address specific needs, values and concerns.

The portfolios identified and approved by the CPUC will incorporate the data generated in planning activities at sister agencies and the CAISO and also inform subsequent cycles of those activities. This will ensure ongoing consistency in the high-level planning and procurement activities that take place across California's electric sector. In that way, the CPUC's IRP process can provide the foundation for a robust process alignment plan as discussed in **Chapter 7**.

The high-level steps of the proposed IRP process are summarized below (see also Figure 2.1). More detail on each step, and how staff proposes these steps to be taken for IRP 2017-18 and future cycles, is provided in the chapters that follow.

1. <u>CARB Establishes GHG Planning Targets</u>: CARB, in coordination with the CPUC and CEC, establishes GHG emission reduction targets for the electric sector, and each LSE and POU, for use in IRP. The planning targets may be revisited in subsequent cycles of IRP.
2. <u>CPUC Adopts Reference System Plan and LSE Filing Requirements</u>: CPUC develops and vets the assumptions to be used in IRP modeling, including reliability needs; conducts modeling to identify optimal combinations of resources under different assumptions about the future; selects a portfolio of future resources (Reference System Portfolio); and articulates an action plan (Reference System Action Plan) that best achieves multiple state goals, including meeting GHG reduction and reliability targets at least cost in the CAISO balancing authority area (BAA).

   It is possible for the Reference System Plan to direct Energy Division staff or LSEs to undertake specific policy or procurement-related activities, if such activities are merited by analysis and the available record. For example, as further explained in **Chapter 6**, the Reference System Plan may be used to inform the CAISO TPP; authorize procurement if a need is identified; provide a marginal GHG abatement value for use in the other resource proceedings; and/or justify a new track or proceeding to further explore any capital intensive, long-lead time resources indicated to be beneficial.

Based on the Reference System Plan, the CPUC articulates specific guidance for LSEs on what LSE Plans filed with the CPUC must include. The Commission votes to adopt the Reference System Plan (including a portfolio and action plan) and final filing requirements for LSEs in one decision.

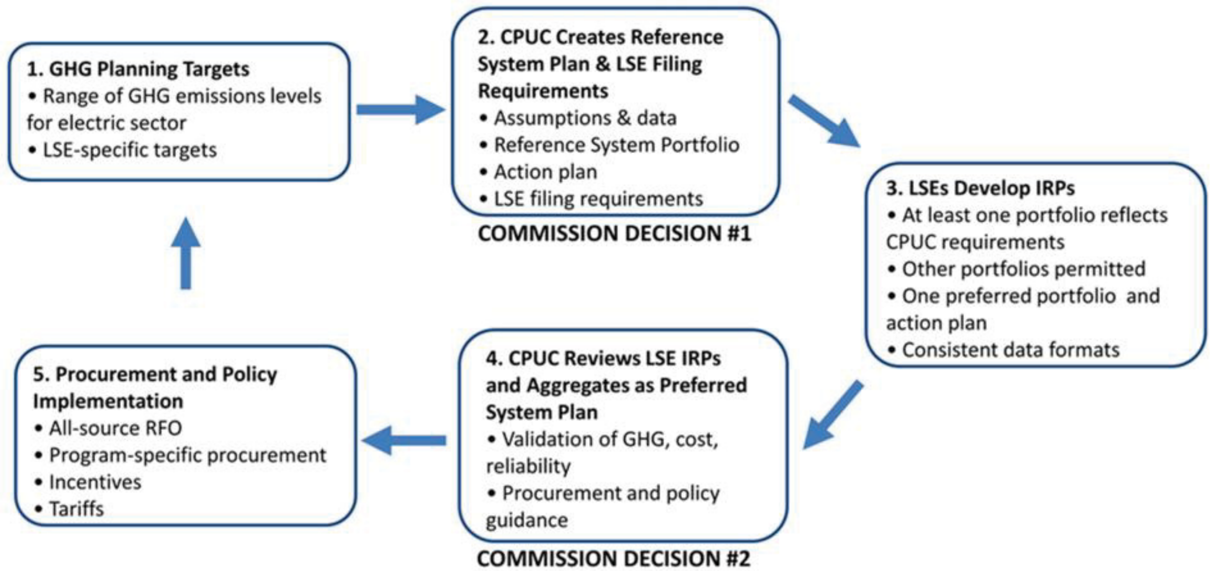
3. LSEs Develop Plans: The Reference System Plan adopted by the Commission forms the basis for subsequent modeling or other analytical work by LSEs to develop their respective LSE plans. LSEs develop and file their own LSE Plans, which will include each LSE's preferred portfolio and recommended set of short-term actions, including any requested procurement authorizations.

4. CPUC Reviews LSE Plans: CPUC reviews all LSE Plans individually and then aggregates the LSE-preferred portfolios into a single portfolio of resources for evaluation for consistency with state goals, including GHG emissions reduction and reliability. If the aggregate portfolio and corresponding short-term actions are reasonably consistent with the Reference System Plan and with state goals, the CPUC approves (or "certifies" in the case of CCAs)[8] the individual LSE Plans. The Commission votes on the aggregate portfolio and corresponding short-term actions to serve as the "Preferred System Plan," formally replacing the Reference System Plan in that IRP cycle. Similar to the Reference System Plan, the Preferred System Plan includes a set of short-term actions and activities (Preferred System Action Plan) necessary to implement the Preferred System Portfolio. The Preferred System Portfolio is also expected to serve as the "policy preferred portfolio" used in the CAISO TPP if a resource or infrastructure need is identified.

5. IRP Implementation: The CPUC determines whether to authorize new procurement, program funding, or tariff changes to meet the requirements of the Preferred System Plan.

[8] According to Public Utilities Code Section 454.52(b)(3), a CCA's plan shall be submitted to its governing board for approval and provided to the Commission for "certification."

Figure 2.1: Proposed IRP Process.



The proposed IRP process achieves the following objectives:

- Helps the state minimize the cost of achieving SB 350 goals. The Reference System Plan represents a least-cost, optimal statewide solution to meet the state's GHG reduction goals, satisfy reliability requirements, and achieve other state policy goals.
- Facilitates LSE Plan preparation. The Reference System Plan is built with public data to the extent feasible and provides valuable information to the LSEs about the relative cost-effectiveness of resource additions and potential retirements across the state.
- Provides information for future policy and planning decisions. Using the Reference System Plan as a guide for LSE Plan development can allow both the CPUC and LSEs to identify system wide-opportunities for joint investments needed to achieve SB 350 goals, such as for capital intensive, long-lead-time resources (e.g., bulk storage or out-of-state wind). It also allows for the results of choices made by individual LSEs to inform and influence other LSE's future plans.
- Directs LSEs toward the optimal resource mix without being overly prescriptive. The proposed process allows different LSEs across the state to choose from a common reference point the elements that best fit their load and resource portfolio. Rather than depending on specific procurement direction from the CPUC, LSEs have the flexibility to use their own models and prepare their own Plans accounting for their specific resource and program costs.
- Creates a level playing field for all CPUC-jurisdictional LSEs. The proposed process ensures that each entity can meet IRP requirements under a common set of guidelines, but also acknowledges that different LSE types have different needs and requirements to fulfill.

The fundamental differences between resource planning under the previous Long-Term Procurement Plan (LTPP) process (e.g., R.13-12-010) and the proposed IRP process described above are:

- LTPP historically identified additional supply-side resources (mainly natural gas-fueled generators) needed to ensure grid reliability in a cost-effective manner, given a fixed demand forecast and supply resource projections provided by individual and separate supply- and demand-side resource procurement programs. Responsibility for meeting those needs rested with individual IOUs, with costs shared by all benefiting customers.
- IRP will identify <u>an optimal mix of supply- and demand-side resources</u> needed to achieve <u>GHG reduction and other state goals</u> and ensure grid reliability in a cost-effective manner (per SB 350). Responsibility for meeting those needs will be shared by all CPUC-jurisdictional LSEs.

IRP 2017–2018

Considering the California electricity sector's unique position and the complexity of transitioning away from the existing resource planning paradigm, staff proposes that the IRP proceeding's overarching goal in 2017-18 be to establish the essential groundwork and structure for IRP, and to move through the entire process once. Efforts should be focused on generating the optimal portfolio to meet SB 350 goals, establishing a formal process for filing and reviewing integrated resource plans, and defining the relationship between IRP and procurement with respect to other resource programs and proceedings at the CPUC.

In this initial IRP cycle, staff intends for the Reference System Plan, its associated GHG Planning Price, and the Preferred System Plan to inform the CPUC's other resource and program-specific energy proceedings, providing them the context necessary to make judgments about specific near-term resource and program goals. In addition, the IRP proceeding will evaluate the need for short-term procurement to meet reliability needs (see Box 4.2), and it will evaluate opportunities for long lead-time investments. Incremental procurement may be authorized depending on the needs identified in the individual IRP filings. Individual LSEs will continue to be expected to meet reliability, environmental, and cost requirements for their respective customers. The Preferred System Portfolio generated in 2018, moreover, is expected to inform the CAISO TPP and procurement and infrastructure authorizations to the extent feasible and appropriate.

In this way, staff expects IRP 2017-18 to demonstrate the feasibility of the proposed process and set the course for future rounds of IRP. The lessons learned from this first cycle will be incorporated into a revised, multi-year IRP process, beginning in 2019 and operating over a two-year cycle.

As noted earlier, below are the defining aspects of IRP 2017-18 as they appear chronologically within the proposed IRP process:

- Coordination between CARB, CPUC, and CEC in establishing GHG planning targets for the electric sector and individual LSEs and POUs (**Chapter 3**).

- Developing and operationalizing a model to generate an optimal portfolio of resources in 2017 that achieves SB 350 goals (i.e., Reference System Plan) (**Chapter 4**).
- Establishing expectations for what LSEs should include in their IRP filings, how those plans will be evaluated this cycle, and how they will be aggregated into the Preferred System Plan (**Chapter 5**).
- Defining expectations for IRP procurement based on the Reference System Plan and the Preferred System Plan, both in IRP 2017-18 and in future cycles (**Chapter 6**).
- Specifying expectations for alignment between IRP and other resource programs and proceedings at the CPUC, as well as coordination among the CPUC, CEC, CARB, and CAISO (**Chapter 7**).

Chapter 3: Establishing GHG Planning Targets in IRP 2017-18

Chapter Summary

CARB, CPUC, and CEC have initiated a joint agency process to achieve the shared goal of establishing GHG planning targets in 2030 for the IRP process. CPUC and CEC staff recommends using the results of CARB's 2017 Climate Change Scoping Plan Update (Scoping Plan) as a starting point to inform the electric sector GHG emissions reductions target for IRP. For the purposes of dividing the electric sector target between the CPUC's and CEC's respective IRP processes, staff proposes to use a bottom-up approach based on CARB's draft methodology for the 2021-2030 allowance allocation to electric distribution utilities (EDUs) under the Cap-and-Trade program. CPUC staff then proposes using a CAISO system-wide marginal GHG abatement cost (i.e., "GHG Planning Price") as a proxy for determining the LSE portion of the electric sector GHG planning target and the individual LSE-specific GHG planning targets in IRP 2017-18.

GHG Target Setting is an Interagency Process

SB 350 creates a role for CARB, in coordination with the CPUC and CEC, to establish GHG emission reduction targets for the electric sector and each LSE and POU for use in IRP. The CPUC has a statutory deadline for adopting its IRP process for LSEs, and POUs have statutory deadlines for when they must adopt IRPs.[9] Both CPUC and CEC have independent, formal, IRP proceedings for entities under their respective jurisdictions. CARB, CPUC, and CEC have initiated a joint agency process to achieve the shared goal of establishing GHG planning targets in 2030 for IRP pursuant to statutory requirements while recognizing and respecting each agency's procedures and authority.

For LSEs and POUs to begin implementing IRP, the CPUC, CEC, and CARB must undertake three steps to establish GHG planning targets for LSEs and POUs:

1. Define the electric sector GHG emissions reduction target or target range for use in IRP;
2. Adopt a methodology to apportion this target for planning purposes in the CPUC's and CEC's respective IRP processes; and
3. Adopt a methodology for setting LSE- and POU-specific GHG emission reduction targets.

The first two steps were the focus of a joint CPUC and CEC staff discussion document, "Options for Setting GHG Planning Targets for IRP and Apportioning Targets among POUs and LSEs" (or "GHG Options

[9] Local publicly owned electric utilities with an average electrical demand exceeding 700 gigawatt hours, as determined by a three-year rolling average commencing January 1, 2013, must adopt IRPs by January 1, 2019. The Energy Commission must review POU IRPs to ensure they meet the requirements of Public Utilities Code Section 9621.

Paper"),[10] released for party comment on February 10, 2017, and a Joint Agency Workshop on 2030 GHG Emission Reduction Targets for IRP (or "GHG Workshop") held on February 23, 2017. The third step—adopting a methodology for setting LSE-specific targets—was the subject of an Energy Division staff white paper on Implementing GHG Planning Targets in the IRP Process (or "GHG White Paper"),[11] released in November 2016. The CEC and CARB held a joint workshop on April 17, 2017, on potential methodologies to establish POU-specific GHG reduction targets.

The CPUC is on track to issue a decision by Fall 2017 defining its IRP process, and in parallel CARB expects to initiate a process for its Board to consider GHG target-setting in late 2017. CARB is coordinating with the CPUC and CEC to develop a timeline and scope of review that accommodates the ongoing work of LSEs and POUs to develop IRP filings for the CPUC and CEC to review, respectively.

The process of establishing GHG planning targets per SB 350 cannot be accomplished by a simple formula, as the CPUC, CEC, and CARB have different SB 350-related IRP responsibilities. Coordination is therefore critical to ensuring an efficient process that avoids unnecessary regulatory burdens and results in fair application of GHG planning targets across LSEs and POUs. The steps outlined below describe a coordinated interagency approach designed to accomplish the state's GHG goals while also accommodating timing constraints, respecting each agency's authority, and acknowledging the inherent uncertainty of planning for achieving GHG reductions in the 2030 timeframe. Importantly, this process is expected to be iterative, and the results of the GHG-target setting exercise for IRP 2017-18 are expected to inform subsequent rounds of IRP, potentially resulting in revised GHG planning targets for both the CPUC's and CEC's respective IRP processes. The results of IRP 2017-18 may also inform future Scoping Plan Updates by CARB.

Step 1: Define an Overall Electric Sector Emissions Target in 2030 for IRP Purposes

CARB is estimating the electric sector's share of the state's 2030 GHG emission reduction in the 2017 Climate Change Scoping Plan Update (Scoping Plan),[12] which projects emissions by economic sector to achieve statewide 2030 GHG targets. CARB forecasts in its Proposed Scenario that the electric sector's share of total statewide GHG emissions will be in the range of 42 to 62 million metric tons of carbon

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[10] Available at: http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/LTPP/2017/GHGOptionsPaper.pdf

[11] Available at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451662

[12] Available at: https://www.arb.ca.gov/cc/scopingplan/scopingplan.htm.

dioxide emissions ($MMTCO_2e$) in 2030[13] (subject to change pending CARB Board approval), assuming that the Cap-and-Trade Program reduces GHG emissions by 40–85 $MMTCO_2e$ in 2030.[14]

The Scoping Plan does not address how or whether the electric sector's share of the statewide emission reduction target should be used as a planning target in either agency's IRP process. However, CPUC and CEC staff recommend using the Scoping Plan results to inform the initial electric sector GHG planning targets for the IRP process. The Scoping Plan is an appropriate starting point as it achieves multiple objectives critical to achieving SB 350 goals:

- The Scoping Plan is based on a statewide, multi-sector analysis that evaluates GHG reduction opportunities and costs across the California economy, thus capturing the interactive effects of different measures in the electric and other economic sectors.
- CARB's GHG reduction range will allow the CPUC to examine multiple points to better understand the costs associated with achieving additional GHG emissions reductions in the electric sector.
- The Scoping Plan analysis has been vetted through a public stakeholder process.

CPUC staff plans to model several different GHG emission constraints within the Scoping Plan range (see **Chapter 4**) and to evaluate the different outcomes implied by those constraints.

Step 2: Determine a Methodology to Divide the Electric Sector Emissions Reductions Target between the CPUC's and CEC's Respective IRP Processes.

The CPUC, CEC, and CARB are also coordinating to determine how to divide the responsibility for reducing GHG emissions among the CPUC's and CEC's respective IRP processes. This step accomplishes multiple objectives:

- Acknowledges that the CPUC and CEC have different procedures, authority, and SB 350-related requirements for IRP.
- Ensures that the agencies, as well as the public, are able to sum individual LSE and POU GHG planning targets and compare the result against total planning GHG emission reductions for the electric sector in 2030.

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[13] Compared to its 1990 level of 108 $MMTCO_2e$.

[14] CARB also considered four alternative scenarios in the Scoping Plan, including one without a post-2020 Cap-and-Trade Program (Alternative 1), which is associated with greater 2030 GHG reductions achieved in the electric sector. The Scoping Plan acknowledges that the ranges for any sector may change in response to how markets respond to the Cap-and-Trade Program.

- Allows the CPUC to specify a CAISO-wide GHG-reduction target to use as a constraint in IRP modeling, which will result in a Reference System Plan that represents an optimal mix of resources for meeting forecasted load throughout the CAISO balancing authority area (BAA).
- Utilizes a publicly vetted methodology and data.
- Ensures that eventual IRP outcomes are consistent with the requirements of SB 350.

CPUC and CEC staff agree that a bottom-up methodology is appropriate for apportioning the electric sector GHG target among all LSEs and POUs. In order to maintain consistency with existing statewide GHG accounting methodologies, CPUC and CEC staff propose to leverage CARB's draft methodology for the 2021-2030 allowance allocation to electric distribution utilities (EDUs) under the Cap-and-Trade Program, as provided in CARB's Second Notice of Public Availability posted on April 13, 2017.[15] Using CARB's allowance allocation formula, the collective emissions of CPUC-jurisdictional LSEs[16] would comprise roughly 77.2% of total electric sector emissions in 2030, with POUs comprising the remaining 22.8%.

CPUC staff proposes to use this same methodology to establish a CAISO-wide GHG emissions constraint for modeling purposes. Since the CAISO BAA includes several POUs, the CAISO-wide constraint will necessarily reflect some POU emissions; however, the CPUC's IRP process will not optimize POU resource portfolios or emissions. To determine the CAISO-wide constraint for modeling purposes, CPUC staff proposes to multiply the 2030 electric sector target (i.e., a number selected within the Scoping Plan range) by each EDU's proportionate allocation of total 2030 allowances, and then to add up those targets for all EDUs (including both LSEs and POUs) within the CAISO BAA. Using this method, the collective emissions of CAISO-embedded LSEs and POUs comprise approximately 80.6% of total electric sector emissions in 2030,[17] meaning that staff would set the CAISO-wide GHG constraint in the RESOLVE model at 80.6% of the GHG target established for the electricity sector. Because the precise electric sector GHG target has not yet been formally established, multiple GHG constraints will be tested in IRP modeling to allow the agencies to evaluate the range of different outcomes implied by those constraints. This analysis is expected to inform CARB's final decision in establishing GHG targets for IRP, as required by statute.

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[15] See "Post-2020 Electrical Distribution Utilities Allowance Allocation Spreadsheet" available at: www.arb.ca.gov/regact/2016/capandtrade16/capandtrade16.htm. Any subsequent revisions made by CARB to this methodology will be reflected in the CPUC-CEC split for IRP.
[16] CARB's proposed allowance allocation to electric distribution utilities that are IOUs includes the electric demand by CCA customers
[17] Incidentally, CAISO load is forecast to be approximately 80% of statewide electric load in 2030.

Step 3: Defining a Methodology for Setting LSE- and POU-specific GHG Emission Reduction Targets

In parallel with Step 2, both CPUC and CEC staff are coordinating with CARB to develop more refined methods to set LSE- and POU-specific GHG emissions reduction targets in their respective IRP processes.

Using a Marginal GHG Abatement Cost to Establish LSE-specific GHG Planning Targets

CPUC staff proposes developing a CAISO system-wide marginal GHG abatement cost as a proxy for achieving the electric sector 2030 GHG planning target in IRP 2017-18. Specifically, staff proposes that the Commission require LSEs to use the marginal GHG abatement cost (or "GHG Planning Price") of meeting the 2030 electric sector target as a constraint in developing their portfolios, in addition to established reliability standards and other IRP requirements (e.g., serving its customers at just and reasonable rates).

Individual LSE portfolios prepared using the GHG Planning Price would have an associated estimate of total mass-based emissions in 2030. When individual LSEs file their IRPs to the CPUC for review, the CPUC can aggregate each LSE's resource portfolios and associated emissions estimates into a single estimate of LSE emissions, which the CPUC can compare to the initial LSE electric sector target calculated in Step 2.

To arrive at the appropriate GHG Planning Price for IRP, CPUC staff proposes to use the RESOLVE model to define the marginal GHG abatement cost of achieving the CAISO-wide GHG constraint, as defined in Step 2 above. RESOLVE allows specification of a GHG planning target in tons of CO2 equivalent (i.e. Step 2) to constrain the portfolio on an annual basis, and this constraint reflects the collective required emissions targets for all LSEs and POUs within the CAISO. During each of the model runs, RESOLVE searches for combinations of resources subject to the constraint that GHG emissions do not exceed the specified GHG planning target for a given year. The range of resulting GHG abatement costs across the IRP planning horizon (2018–2038) represents an estimate of the costs of reducing GHG emission over time. The GHG Planning price is thus an outcome of the modeling and is directly related to the magnitude of the CAISO-wide GHG constraints that staff proposes to model (see **Chapter 4**).

The GHG Planning Price for the 2017-18 IRP cycle represents the lowest possible price of carbon that would encourage investment in a given portfolio of resources (i.e., the Reference System Portfolio adopted by the Commission), absent a specific mandate or requirement to meet the 2030 GHG reduction target. The GHG Planning Price is entirely distinct from the market prices associated with CARB's Cap-and-Trade Program; it is a modeled outcome that provides insight into the costs of meeting various electric sector GHG planning targets. In other words, GHG Planning Price reflects the cost of meeting the state's GHG goals for the electric sector.

In RESOLVE, the GHG emissions of any given portfolio is calculated using the following formula:

CAISO fuel burn [MMBtu] (gas CCGT, gas CT, gas CHP, gas ICE) X Physical emissions rate [tons/MMBtu]

+ Unspecified imports [MWh] X Deemed emissions rate [tons/MWh]

Consistent with CARB inventory accounting, the model does not give GHG credit for zero-carbon exports from the CAISO. For imports, the model uses CARB's default emissions factor of 0.428 MT of CO2e/MWh. More information on how GHG emissions are calculated in RESOLVE is available in **Appendix B**; also refer to **Chapter 4**.

As discussed in more detail in **Chapter 6**, staff expects that IRP 2017-18 will be used to inform near-term actions and investments, rather than result in specific resource authorizations. For defining LSE-specific GHG planning targets in future cycles of IRP, staff suggests several options:

- Use the 2030 emissions reported in each LSE's preferred portfolio, once approved by the Commission, as the basis for a mass-based GHG planning target for that LSE for the IRP 2019-20 cycle, allowing for any necessary adjustments (e.g., due to load shifting).
- Use IRP modeling, and potentially a revised CAISO-wide GHG constraint containing updated targets for embedded LSEs and POUs, to define a new GHG Planning Price for the IRP process.
- Use CARB's methodology for the 2021-2030 allowance allocation to EDUs to apportion the 2030 electric sector target to all LSEs on a mass-based level.

Rationale for Using a GHG Abatement Cost for IRP 2017-18

Staff's rationale for recommending the GHG abatement cost option (or "GHG Planning Price") is provided below, as evaluated against the objectives for implementation of GHG planning targets first presented in the GHG White Paper[18] released in November 2016. The original objectives identified in the GHG White paper, since revised in response to party feedback, were intended to serve as criteria for evaluating the implementation options and determining the best approach to setting LSE-specific planning targets.

- Revised Objective 1: GHG planning targets should be developed jointly by the CPUC, CARB, and CEC in a manner that is transparent and accessible to provide meaningful public participation.
  - CPUC, CARB, and CEC staff announced their intent to coordinate in establishing the GHG planning targets at a joint agency workshop on February 23, 2017. Agency staff plans to continue providing opportunities for public participation in this process through workshops, staff papers, and other venues.
  - All information supporting the calculation of the GHG Planning Price will be publicly available and vetted in the IRP proceeding during review of the Reference System Plan.
- Objective 2: Any GHG target-setting methodology adopted should be applied in an equitable manner across all CPUC-jurisdictional entities that are required to file integrated resource plans.

[18] Refer to: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451662

- All LSEs would prepare their Plans using the same GHG Planning Price (across the IRP planning horizon of 2018–2038), which will avoid the potentially contentious process of determining and litigating the appropriate allocation of mass-based or intensity-based GHG planning targets among individual LSEs. For example, this process avoids the need to make periodic adjustments in response to shifts in load between IOUs and CCAs, which may be necessary under a mass-based approach.

- Revised Objective 3: GHG planning targets should facilitate optimal solutions to achieve the state's GHG reduction and other policy goals, while enabling each LSE to serve its customers reliably and at just and reasonable rates.
  - GHG planning targets based on a marginal GHG abatement cost can provide an accurate signal for making cost-effective investment decisions across a broad range of LSEs with different resource portfolios. Different LSEs will naturally have different starting emission intensities and different opportunities, some more costly than others, to reduce emissions.[19] To the extent that there are less expensive resources in one LSE's territory than in another's, an approach based on a common marginal GHG abatement price would facilitate a more economically efficient outcome.
  - A price-based metric facilitates LSEs' efforts to maintain just and reasonable rates when making planning decisions.
- Objective 4: GHG planning targets should facilitate planning by providing clear metrics for LSEs to use in developing their integrated resource plans.
  - LSEs will be able incorporate the GHG Planning Price into capacity expansion models and planning efforts in a relatively straightforward manner.
  - A GHG Planning Price would reflect the magnitude of the difference between the LSEs' business-as-usual emissions and their emissions targets.
- Objective 5: Any GHG planning methodology adopted should not discourage LSEs from exploring transportation electrification and other types of fuel switching as potential solutions to reduce GHG emissions.
  - Using a GHG Planning Price would not discourage LSEs from exploring other types of fuel switching as potential solutions to reduce GHG emissions, nor would it explicitly encourage cross-sector solutions.
  - In the longer term, a GHG Planning Price may reflect the need or potential to pursue greater electrification in other sectors if those investments are projected to reduce GHG

[19] For example, allowing one LSE to have a higher ratio of gas-fired generation or energy storage in its portfolio may be desirable because of local reliability needs within that LSE.

more cost-effectively. Comparing the costs of reductions across sectors would be essential for identifying an optimal economy-wide investment strategy.

- New Objective 6: The GHG planning targets incorporated into the IRP process should complement, and not interfere with, existing GHG compliance regimes.
  - The Reference System Plan and GHG Planning Price in this cycle will help other resource-specific proceedings make informed decisions about near-term resource and program goals. The CPUC may use the Preferred System Plan in 2018 as a basis for authorizing any resource procurement needed for reliability purposes, and potentially for GHG-reduction purposes.

Establishing a Method to Estimate LSE and POU Portfolio Emissions for IRP

Both the CPUC and CEC will be evaluating LSE or POU Plans based in part on whether they achieve GHG reductions consistent with the electric sector target, and with individual LSE- and POU-specific targets. This highlights the need for a common method to estimate LSE and POU portfolio emissions. As such, staff recommends that the CPUC collaborate with CEC and CARB to identify ways to estimate the emissions associated with LSE and POU Plans. Areas of potential improvement and alignment on GHG accounting include:

- Unspecified energy imports
- In-CAISO unspecified energy
- Hydropower imports
- Exports resulting from excess RPS generation.

For IRP 2017-18, CPUC staff recommends an interim approach for estimating GHG emissions based on existing GHG emissions factors and protocols used by CARB. More details are provided in **Chapter 5**, and the approach may be revised future rounds of IRP based on stakeholder and interagency feedback. In the meantime, the agencies intend to continue coordinating closely to ensure that any method to estimate emissions associated with each LSE and POU Plan will be consistent with the agencies' other GHG accounting processes, which will help ensure a level playing field for all LSEs and POUs in their planning activities and avoid duplication of efforts.

For example, any method to account for GHG emissions in IRP should also be coordinated with the ongoing efforts pursuant to AB 1110, which requires the CEC, in consultation with CARB, to adopt a methodology for calculating the GHG emissions intensity for each purchase of electricity by a retail supplier to serve its customers.[20] Beginning June 1, 2020, all retail sellers will be required to report and disclose the GHG intensity of their portfolios.

[20] More information on the AB 1110 Implementation Rulemaking is available at: http://www.energy.ca.gov/power_source_disclosure/

Chapter 4: Plan for Developing the IRP 2017-18 Reference System Plan

Chapter Summary

In IRP 2017-18, Commission staff plans to use a capacity expansion model called RESOLVE to produce portfolios of resources that are least-cost under a variety of different possible future conditions. Staff will recommend a single portfolio to use in future planning and procurement activities, propose near-term actions associated with that portfolio, and develop IRP filing guidance for individual LSEs (together comprising the "Reference System Plan"). Staff proposes to organize the development of the Reference System Plan around three primary questions:

A. What resources are needed to reduce GHG emissions in the electric sector?

B. What is the optimal portfolio of resources under different, alternative futures?

C. What investments or actions, if any, should be taken in the short term?

The questions are designed to accomplish the following:

- Explore the impact of a new GHG planning target on the need for new resources
- Ensure that the portfolio selected by the CPUC satisfies all statutory requirements under a range of possible future conditions
- Enable the CPUC to provide procurement and investment guidance to all regulated entities, as well as other decision makers and market actors in California.

Modeling in IRP 2017-18

Staff proposes to use a capacity expansion model called RESOLVE in 2017 to produce portfolios of resources that could be used by the CPUC to meet the statutory requirements of Section 454.51(a) (for more information on RESOLVE, see Box 4.1). Rather than using the model to identify a single, optimal portfolio, staff will identify a series of portfolios that satisfy reliability requirements (see Box 4.2) and are least-cost under a variety of different possible future conditions. Staff will evaluate the various portfolios using cost and other statutorily-required criteria over a planning horizon of 20 years (2018-2038) and recommend a single Reference System Portfolio to use for future planning and procurement activities. Staff plans to revisit the model platform in Fall 2017 to assess whether any changes are advisable for future rounds of IRP.

In addition to providing a portfolio of specific resource types (i.e., Reference System Portfolio), staff plans to develop recommendations for near-term actions (i.e., Reference System Action Plan), and guidance for LSEs for filing their own plans as required by Public Utilities Code Section 454.52. Specifically, the Reference System Plan will consist of the Reference System Portfolio, the Reference

System Action Plan, and guidance for LSEs. Staff recommends that the Commission vote to adopt a Reference System Plan in 2017, and again in the first year of each IRP cycle.

Box 4.1. The Role of the RESOLVE Model in IRP

A capacity expansion model is a computer model that simulates generation and transmission investment to meet forecast electric load over many years, usually with the objective of minimizing the total cost of owning and operating the electrical system. Capacity expansion models can also be configured to only allow solutions that meet specific requirements, such as providing a minimum amount of capacity to ensure the reliability of the system (see also Box 4.2), or maintaining greenhouse gas emissions below an established level.

RESOLVE is a type of capacity expansion model designed to inform long-term planning questions around renewables integration in systems with high penetration levels of renewable energy. It co-optimizes investment and dispatch for a selected set of days over a multi-year horizon in order to identify least-cost portfolios for meeting renewable energy targets and other system goals.

The RESOLVE model's optimization scope covers the CAISO balancing area including POU load within the CAISO. RESOLVE models but does not optimize loads and resources outside of the CAISO balancing area. Staff plans to represent future POU resources outside the CAISO balancing area as "fixed" quantities in RESOLVE that are not subjected to the optimization exercise, using information derived from sources such as the 16 POU integrated resource plans filed with CEC.

The assumptions Staff proposes to use for capacity expansion modeling are available on the Commission's website.[21] Question 9 in the ruling specifically solicits party feedback on the proposed assumptions.

The RESOLVE model and user's manual[22] will also be available online at the same time the draft results of staff's modeling activities are released. Parties will have an opportunity to comment formally on the RESOLVE model, associated documentation, and draft modeling results.

Box 4.2. Reliability in IRP Modeling

Reliability is a core consideration in the IRP process and in IRP modeling. The RESOLVE capacity expansion model that staff will use to develop the Reference System Plan adds resources to ensure that

[21] Assumptions are available at: http://www.cpuc.ca.gov/irp_proposal/
[22] The RESOLVE model and associated documentation will be publicly available at the time the draft Reference System Plan is released.

every portfolio it produces has sufficient system, local, and flexible resources. The magnitude of system and local need are not determined by the RESOLVE model itself, but are constraints that must be met as new resources are added. The amount of system and local needs must be determined through other analytical activities.

System resource needs are represented as a mandatory planning reserve margin of 15%. If insufficient resources are available to meet the planning reserve margin, RESOLVE will add resources until the reserve margin requirement is satisfied. RESOLVE considers the capacity contribution from most resources using conventions consistent with the current resource adequacy program except for wind and solar resources. RESOLVE estimates capacity contribution from the total wind and solar portfolio using Effective Load Carrying Capability methods.

In IRP 2017-2018, local needs are based on results of the most recent round of long-term Local Capacity Technical Analysis published in the CAISO's 2016-17 Transmission Plan. Staff anticipates that LSEs will include any estimates of local needs in their own territories in their LSE Plans. Any deviations between LSE estimates and the assumed local needs embedded in the Reference System Plan will be addressed in the process of reviewing and approving the LSE Plans.

Flexible needs are handled in RESOLVE in two ways. First, ramping constraints are enforced, meaning that RESOLVE must always ensure that resources that can meet ramping needs are available at the appropriate times. Second, RESOLVE addresses any flexibility problems it encounters by making an economic decision about whether to curtail existing resources, or add new resources to the system, depending on which option results in the lowest costs. (Note: To quantify the costs associated with avoiding curtailment, staff will also examine the effect of manually imposing a limit on curtailment in RESOLVE.) Importantly, RESOLVE does not represent flexibility as a capacity "need" in the same way that local and system resource adequacy are represented. Instead, RESOLVE balances supply and demand using the least-cost combination of curtailment and new investment. This long-term planning approach to ensuring flexibility needs are met diverges from the current state of near term Flexible RA capacity requirements. As both IRP and the Flexible RA capacity program develop and the market gains more experience with participating in a grid that includes large quantities of variable renewable energy, either – or both – approaches may need to evolve.

Additional, more detailed modeling may be necessary for confirming that the Reference System Plan, LSE Plans, and Preferred System plan meet all relevant reliability standards, including local reliability needs. CPUC staff, including the Energy Resource Modeling team, anticipate additional collaborative work on this matter with parties, sister agencies, and the CAISO. CPUC staff anticipates that the IRP Modeling Advisory Group first convened in fall of 2016 will be a major forum for further exploring modeling needs and issues in IRP.

Developing the IRP 2017-18 Reference System Plan

In order to produce a Reference System Plan that is consistent with statutory requirements, staff proposes to organize its modeling activity around three primary questions:

A. What resources are needed to reduce GHG emissions in the electric sector?

B. What is the optimal portfolio of resources under different, alternative futures?

C. What investments or actions, if any, should be taken in the short term?

Question A is designed to produce a starting point for considering the impact of a new GHG planning target on the need for new generation, DERs, and transmission. Question B is designed to ensure that the portfolio selected by the CPUC for use in the Reference System Plan (i.e., the Reference System Portfolio) meets all statutory requirements, including prioritizing air quality benefits in disadvantaged communities, without exposing ratepayers to excessive financial risks (i.e., the possibility or frequency of high costs). Question C will enable the CPUC to provide guidance to all regulated entities, as well as other decision makers and market actors in California, regarding the relative value of different categories of demand- and supply-side resources for meeting the state's goals.

Below staff proposes specific cases to run in the RESOLVE model and specific metrics for evaluating RESOLVE results and answering each of the three primary questions listed above. The descriptions are organized by the three primary questions. In some cases, staff proposes additional, more detailed questions to facilitate answering the broader, primary questions.

To make the description of model cases more accessible to a wider audience, staff uses qualitative descriptions of relevant assumptions rather than specific values. Typically, these descriptions provide an indication of the relative magnitude of the underlying value relative to a range of reasonable values. A detailed list of the specific values associated with each assumption is available in the 2017 RESOLVE Model Documentation on IRP Inputs and Assumptions.[23] Please also refer to **Chapter 3** for more information on how the GHG planning constraint is proposed to be determined.

Question A: What resources are needed to reduce GHG emissions in the electric sector?

Over the past decade and a half, the RPS and reliability needs together have driven the procurement of new supply-side resources by LSEs under CPUC jurisdiction. The IRP process is tasked with considering the possibility that the state's GHG emission reduction goal will require new procurement of either supply or demand-side resources beyond what is already needed for RPS and reliability purposes. IRP must also consider whether decreases in procurement of certain resources may be most responsive to the state's GHG emission reduction and other goals. Question A is designed to produce a starting point for considering the impact of a new GHG planning target on the amount of new generation, DERs, and transmission that are needed to achieve state goals.

[23] Full documentation of all draft assumptions is available online at: http://www.cpuc.ca.gov/irp_proposal/

The answer to Question A is dependent on the amount of emissions reductions the electric sector is asked to achieve. To address this first question, staff plans to run the RESOLVE model to generate a least-cost portfolio under four different policy assumptions about the size of the electric sector's share, with respect to that of other sectors, in reducing statewide GHG emissions by 2030.

1. Default: The electric sector achieves an emissions level by 2030 that is equivalent to the upper end of the range attributed to it in CARB's Draft Scoping Plan Scenario (62 MMT by 2030).
2. Moderate Share of Economy-Wide Emissions Reductions: The electric sector achieves an emissions level by 2030 that is equivalent to the middle of the range attributed to it in CARB's Draft Scoping Plan Scenario (52 MMT by 2030).
3. Large Share of Economy-Wide Emissions Reductions: The electric sector achieves an emissions level by 2030 that is equivalent to the lower end of the range attributed to it in CARB's Draft Scoping Plan Scenario (42 MMT by 2030).
4. Extra Large Share of Economy-Wide Emissions Reductions: The electric sector achieves an emissions level by 2030 equivalent to what is attributed to it in CARB's Alternative 1 scenario (30 MMT by 2030); this implies that additional electric sector investments beyond those included in the CARB's Draft Scoping Plan Scenario are used to achieve the state's GHG emission reduction goals.

It is important to note that the regulatory mechanisms to achieve each of these electric sector emissions levels may require further study and analysis. For example, since many LSEs currently have large banks of Renewable Energy Credits (RECs) that could be used to meet a 50% RPS in 2030 according to the current compliance rules, the current RPS, on its own, is not likely to drive the investments needed to achieve the physical emissions reductions represented in these cases. This issue is discussed in more detail in **Chapter 6**. Parties are encouraged to offer comments on regulatory mechanisms and analytical approaches in response to Question 29c in the ruling.

Key default assumptions for the Moderate Share and Larger Share cases are shown in Table 4.1. Additional detail is provided in **Appendix B**.[24] The subsequent section of this chapter introduces the sensitivities staff proposes to model.

Table 4.1. Key default assumptions for RESOLVE model runs.

Assumption	Default	Moderate	Large	Extra Large
2030 Electric Sector GHG Emissions Target[1]	62 MMT	52 MMT	42 MMT	30 MMT
Effective RPS[2]	Least-cost[3]			
EE	2016 Mid AAEE + AB802[4]			
DR-Shed (New)	LBNL DR Potential Study Phase 2 Report[5]			
DR-Shift (Advanced)	LBNL DR Potential Study Phase 2 Report[5]			

[24] The complete set of assumptions is available online at: http://www.cpuc.ca.gov/irp_proposal/

DR-Shape (TOU)	MRW Scenario 4 X 1.5[6]
DR-Shimmy	Not considered
BTM PV	2016 IEPR Mid PV
ZEV	CARB Scoping Plan Scenario (3.6 M LDV by 2030)
Storage	470 MW[7] + least-cost additions[3]
OOS Wind, Existing Tx	Least-cost (max 2,000 MW[8])
OOS Wind, New Tx	0[9]
Net Export Limit	5,000 MW[10]

[1]This table reflects the total GHG target for the California electric sector, derived from CARB's Draft Scoping Plan Update. The actual modeled amount in RESOLVE will reflect CAISO's share of the total, which is approximately 80%, as described in **Chapter 3**.
[2]RPS achieved without counting existing banked RECs; RPS compliance-based achievement may be higher.
[3]The RESOLVE model will add new resources if they are part of part of the least-cost combination of resources that meet the GHG emissions target.
[4] Preliminary results for energy efficiency savings potential reflecting Assembly Bill 802 direction indicates that additional savings to 2015 AAEE that may be cost-effective, feasible and reliable. (http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11189)
[5] Lawrence Berkeley National Laboratory, *2015 California Demand Response Potential Study: Final Report on Phase 2 Results.* 2016. Available at: http://www.cpuc.ca.gov/General.aspx?id=10622
[6] Scenario 4 in the Joint Agency Staff Paper on Time-of-Use Load Impacts escalated by 1.5X. (http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN210253_20160209T152348_Joint_Agency_Staff_Paper_on_TimeofUse_Load_Impacts.pdf).
[7] Amount of storage already procured.
[8] Assumed amount of OOS wind that is currently available to serve CAISO load on existing transmission
[9] Some potential sources of OOS wind energy are assumed to require new transmission in order to serve CAISO load; these sources are not considered in these four cases, but are explored in sensitivities.
[10] Middle of range used in CAISO's recent study of regional energy market. (https://www.caiso.com/informed/Pages/RegionalEnergyMarket.aspx)

Staff will report at least the following set of metrics for the year 2030 for the portfolio produced from each model run. See Appendix D for a description of the data files staff will provide to describe the Reference System Portfolio.

1. Incremental cost (capital, operating costs and customer costs[25] that are incremental to the costs previously authorized by the CPUC)

[25] Customer costs are defined as the net costs incurred by customers rather than LSEs in the process of adding the resource to the system. For example, customer costs include the cost of a new BTM PV system, or the cost net of incentives that customers pay for technologies they install to reduce energy use.

2. New resources added to system (by capacity and technology type)
3. GHG emissions
    a. Total emissions (MMT CO2e)
    b. Marginal GHG abatement cost ($/ton)
4. Reserve margin (as %)

For each metric, the values will be compared across the four main cases corresponding to the four different GHG emission reduction targets. The results will reflect the range of the incremental supply resource need and associated costs implied by different assumptions about the electricity sector's share in achieving the state's GHG emission reduction goal. These results will provide a point of reference for answering Questions B and C.

Additional metrics to be considered in selecting the Reference System Plan are described under Question B below. The implications of fuel switching and other demand-side assumptions are also explored in other cases described under Questions B and C.

Methodology for Projecting Costs

Staff proposes to make the enumeration of cost and rate impacts of alternative portfolios a focal point of the IRP process. One of the most complex aspects of developing a functional IRP process in California is balancing the multiple state policy objectives that electric sector investments could potentially serve. Including cost impacts with each portfolio produced as part of the IRP process will allow decision-makers to reconcile the sometimes competing demands of different mandates and policy objectives in a transparent manner.

The RESOLVE model considers two categories of cost: (1) the fixed costs of new generation and transmission infrastructure, and (2) the total variable costs to operate the CAISO system. However, these costs represent only a fraction of utilities' total revenue requirements. The embedded costs in today's energy system (i.e., "non-modeled costs") are not explicitly modeled in RESOLVE, but are generally expected to increase over the IRP time horizon and drive retail rate increases. Information about these non-modeled costs may give decision-makers insights into the impact of IRP scenarios on utilities' rates. However, there is no single source or consistent methodology for such projections. As part of the longer-term analytical work planned for IRP, Energy Division intends to develop a proposal for projecting rates over the IRP time horizon based on the most accurate and up-to-date cost data available.

Question B: What is the optimal portfolio of resources under different, alternative futures?

To answer the second primary question, staff proposes conducting two rounds of analysis. The first round of analysis will be designed to quantify cost impacts on the electric sector. This analysis will be based on modeling results, similar to what was described under Question A. The second round of analysis will be designed to assess other types of impacts, including impacts on disadvantaged communities. To the extent that modeling results are useful and actionable in the second round of analysis, they will be used as well. Staff anticipates that the second round of analysis will also include information from sources supplemental to the results of the capacity expansion modeling.

For the first round of analysis, staff will allow the model to select a least-cost portfolio under a variety of different assumptions about future conditions. Staff proposes to model each of the different assumptions about future conditions shown in Table 4.2 and Table 4.3. Table 4.2 shows a list of sensitivities, in which only a single future assumption is changed relative to the best estimate of future conditions. Table 4.3 shows a list of futures, which involve changes to multiple assumptions. For more information on the specific assumptions that define each sensitivity and future, refer to **Appendix B**, the Inputs and Assumptions document, and the Scenario Tool, all available on CPUC's website.[26]

It should be noted that CAISO "regionalization" is not specifically proposed as an alternative future for study in IRP 2017-18. The RESOLVE model has already been used to study the possible benefits and consequences of a regional transmission grid in recent study commissioned by the CAISO, and staff does not propose revisiting those questions in the context of IRP. Instead, staff proposes more narrowly examining the specific costs and benefits of making OOS wind available to serve CAISO load (see explanation under Question B.3 below). This analysis may provide a starting point for a more detailed public process for reviewing different forms and pathways through which OOS wind could become accessible.

Table 4.2. Sensitivities (one assumption changes relative to default case)

Name	Description
EE-High	high levels of EE (2X Mid AAEE)
EE-Low	low levels of EE adoption (2016 IEPR Mid AAEE)
BTM PV-High	high BTM PV adoption (2016 IEPR High)
BTM PV-Low	low BTM PV adoption (2016 IEPR Low)
ZEV Flex	ZEV charging responds to grid conditions
Bldg Elect-High	high level of building electrification
PV Cost High	high future PV costs
ST Cost High	high future storage costs

[26] Full documentation of all draft assumptions is available online at: http://www.cpuc.ca.gov/irp_proposal/

PV Cost Low	low future PV costs
ST Cost Low	low future storage costs
Early Retirement	fossil plants retire after 25 years instead of 40
CHP Retirement	early retirement of baseload CHP

Table 4.3. Futures (multiple assumptions change relative to default case)

Name	Description
High DER	high levels of all DERs, including BTM PV, ZEV, EE, DR
High Load	high levels of DERs that increase load (ZEV, bldg elect.), low level of DERs that decrease load (EE, DER, BTM PV)
Flex Challenged	high load, low PV costs, high storage costs, and early retirement of fossil

The First Round of Portfolio Analysis Focuses on Electric Sector Costs

Examining the metrics described under Question A above will produce an overview of how different future conditions affect the optimal portfolio. To develop a more focused set of information for the purpose of selecting a portfolio to serve as the Reference System Plan, staff proposes to answer an additional subset of questions about portfolio costs:

B.1 What is the least-cost portfolio under different assumptions about future conditions?

B.2 What resources tend to increase or decrease financial risk under different assumptions about future conditions?

B.3 Are there any resources that increase costs but decrease financial risk overall?

Non-financial risks are embedded in the assumptions about future conditions that are used to answer the questions listed above. For example, the “high cost PV” and “high cost storage” sensitivities could represent futures in which there have been disruptions to the supply chain. Parties are welcome to propose additional sensitivities that capture risks not currently captured (see Question 11-12 in the ruling).

Staff will address Question B.1 by running the model under each different sensitivity and future and then comparing the cost of the portfolio produced in each run against the cost of the portfolios produced in the other runs. Staff will address Question B.2 by analyzing the relationship between portfolio composition and the distribution of costs across the various sensitivities and futures listed in Tables 4.2 and 4.3.

Staff will address Question B.3 by examining three types of capital-intensive, long-lead-time resources:

- OOS wind (minimum 3,000 MW)
- Long-duration storage (minimum 1,300 MW)

- Additional geothermal (minimum 1,000 MW)

Staff proposes to run the model for each of these resource types against the full range of sensitivities and futures described above (except where redundant). If the specified minimum amount of the resource is not selected by the model, staff will direct the model to include the minimum quantity. Staff will then calculate the maximum cost associated with each resource. By comparing those costs with costs for the portfolios from Question A, staff will determine whether forcing in any resources appears to reduce risk.

If the results developed to answer Question B.3 indicate that any of the long lead-time resources appear to offer significant value, additional cases may be evaluated to help focus CPUC's follow-up activities. For example, the value of some of these resources (including, but not limited to OOS wind) may be affected by different transmission infrastructure options within and outside of California. If merited by the initial modeling results, data compiled in the Renewable Energy Transmission Initiative 2.0 Plenary Report will used to explore the potential costs and benefits of alternative transmission projects. While modeling will not provide complete or comprehensive answers, it may help the CPUC determine how to orient its own participation in western transmission planning processes (see also "The New IEPR–IRP–TPP Process Alignment" in **Chapter 7**).

The Second Round of Portfolio Analysis Focuses on Other State Goals

To inform selection of a portfolio for the Reference System Plan, staff plans to answer another question:

B.4 Which portfolio best facilitates the achievement of other state goals?

To answer Question B.4, staff proposes to consider the implications of different types of risk for the achievement of different state goals. Table 4.4 below shows the state goals that the portfolio is intended to help achieve, in the order they appear in statute, along with potential risks and staff's proposed approach to analyzing the risks.

Table 4.4. Potential Risks Associated with IRP-Related SB 350 Goals and Staff's Recommended Analytical Approach.

State Goal	Potential Risks	Approach to Analysis for Reference System Plan Development
Identifying a diverse and balanced portfolio (454.51)	• Overdependence on single, large projects • Overdependence on single technologies (supply chain risk, siting risks)	• Qualitative review of portfolio diversity
Meeting state GHG targets (454.52(a)(1)(A))	• Overdependence on single, large projects • Supply chain constraints and/or technology deployment limitations • Shortfall in customer adoption of	• Qualitative review of portfolio diversity • Quantitative analysis of portfolios with lower DER levels • Quantitative analysis of portfolio

	demand-side measures	with higher resource costs
Complying with state RPS (454.52(a)(1)(B))	• Low risk because of existing state program	• Enforce modeling constraint that RPS target be met
Ensuring just and reasonable rates for customers of electrical corporations (454.52(a)(1)(C))	• Excessive or premature investment • Load departure (if PCIA does not function properly)	• Quantitative analysis of rates and costs associated with each portfolio • Load departure not directly addressed in Reference System Plan because considers CAISO system as a whole
Minimizing impacts on ratepayer bills (454.52(a)(1)(D))	• Costs of generation resources and DERs • Transmission costs	• Quantitative analysis of rates and costs associated with each portfolio
Ensuring system and local reliability (454.52(a)(1)(E))	• Insufficient procurement of resources needed to maintain reliability • Demand side program achievements fall short of goals	• Enforce 15% planning reserve margin in modeling • Enforce local reliability requirement based on 2016-17 Transmission Plan • Quantitative analysis of portfolios with lower levels of DERs that reduce demand
Strengthening the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities (454.52(a)(1)(F))	• Risk to bulk transmission system is low because of existing Transmission Planning Process • Risk to distribution system is low because of existing Distributed Resource Planning process • Climate change and job loss are risks to local communities	• Qualitative analysis
Enhance distribution system and demand-side energy management (454.52(a)(1)(G))	• Distribution system improvements or demand side programs are mismatched to system needs and other state goals	• Quantitative analysis of sensitivities with different levels and types of DERs
Minimizing air pollutants with early priority on disadvantaged communities (454.52(a)(1)(H))	• Fossil fuel reduction does not occur in the types of plants that most affect disadvantaged communities	• Quantitative, geospatial analysis of potential impacts of fuel reduction on air pollution relative to disadvantaged communities

To the extent possible, staff will quantify the total system and resource cost associated with incremental improvement in each type of goal so the risks and costs can be weighed against one another. Staff will also use professional judgment to characterize the likely impacts of different portfolios on state goals. Staff does not anticipate developing a quantitative scoring system for each type of risk or goal this cycle, as such systems risk creating the false appearance of precision and masking what are fundamentally general, subjective judgments. Instead, staff proposes to provide a narrative explanation of the relative impacts of different types of portfolios on different state goals. Parties will have the opportunity to comment on these qualitative assessments, along with all of the analysis.

Parties are encouraged to suggest feasible alternative or supplemental approaches for defining, quantifying different types of risks, and/or assigning a financial value to them (see Question 14 in the ruling).

How DACs will be Considered in Preparing the Reference System Plan

To inform the development of the Reference System Plan and its consideration of disadvantaged communities, staff will conduct the post-processing analyses detailed below.[27] The results of these analyses will be presented during the workshop on the draft Reference System Plan to help determine the appropriate use of these results in informing the procurement process and in developing metrics to track the ability of different portfolios to contribute to the goal of minimizing localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities. In addition to these analyses, staff will carefully consider recommendations for overcoming barriers faced by DACs described in two recent studies by CEC and CARB.[28]

For the purposes of IRP, communities that score at or above the 75th percentile[29] in the CalEPA's CalEnviroScreen 3.0 will be defined as "disadvantaged."[30]

Demand-Side Resources

In the current version of RESOLVE, load modifications implied by demand-side resources are applied uniformly across the CAISO load. As a result, while the model can provide information about the costs associated with different levels of demand-side resources, it does not offer insight into where those resources are most likely to be developed or whether they are more likely to be developed inside or outside of DACs.

The ability of a capacity expansion model to represent the location of demand-side resources depends on the availability of location-specific information about the costs and benefits of those resources. It is

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[27] Because capacity expansion modeling looks at the electrical system as a whole, post-processing is required to analyze the implications of system-level results for individual communities.
[28] See https://efiling.energy.ca.gov/getdocument.aspx?tn=214830 and https://www.arb.ca.gov/msprog/transoptions/draft_sb350_clean_transportation_access_guidance_document.pdf
[29] CalEPA is currently determining the percentile of its CalEnviroScreen 3.0 tool that is defined as "disadvantaged." If not defined within the timeframe of Reference System Plan development "at or above the 75th percentile" is recommended to be used.
[30] http://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30.

anticipated that ongoing work in other proceedings, including DRP, IDER, and EE, will eventually inform the development of a supply curve of location-specific DERs in IRP, and the cost of each DER would reflect its net location-specific costs and benefits. Key challenges for the development of such a supply curve will be determining the appropriate level of geographic granularity for use in capacity expansion modeling and the appropriate way to bundle different DER types. Greater geographic and technological granularity would also be expected to extend model runtime.

Supply Side Resources

Supply-side resources in RESOLVE are separated into very coarse geographic regions. Staff proposes to approximate the amount and type of new supply-side resources developed in DACs in each portfolio (i.e., MW amount of new fossil and new renewables per DAC).

Questions staff aims to answer through analysis include:

- How does the amount of new generation in geographic regions with different populations of DAC members vary by portfolio?
- Are there any procurement strategies that appear to increase or decrease the amount of new fossil or renewable generation in geographic regions with more DAC members?

Air Pollution and GHG in DACs

The selection of the Reference System Plan will be informed by its impact on air pollution. In order to determine the impacts of various portfolios on air pollution, staff will examine the total fuel consumption in each year (2016-2030) for each type of gas plant for each portfolio (across multiple portfolios/scenarios/sensitivities). By calculating the impact of fuel consumption reduction by plant type on GHG and air pollutant emissions, weighted by the distribution of plant types in DACs, staff may be able to identify portfolios and procurement strategies that reduce power plant air pollution and GHG emissions in DACs. Additionally, staff plans to calculate the costs associated with portfolios yielding the greatest and least reductions of GHG and air pollutant emissions to allow for cost comparison across portfolios.

Questions staff aims to answer through analysis include:

- How do power plant air pollution emissions in DACs vary by portfolio?
- Are there any procurement strategies that appear to reduce power plant air pollution and GHG emissions in DACs?

Portfolio Analysis Concludes with a Recommendation Based on All Criteria

The final question that staff proposes to address is:

B.5 In consideration of electric system costs, resource costs, and all other state goals, what is the optimal portfolio for planning purposes?

Staff will consider the cost information developed by answering Questions B.1–B.3 as well as the information developed by answering Question B.4 in order to make a final recommendation for the portfolio to be included in the Reference System Plan. Staff anticipates that the CPUC will adopt a portfolio by Decision; the portfolio ultimately adopted by the CPUC may differ from the one recommended by staff.

There are many possible methodologies that staff could use to develop a final recommendation for the portfolio to be included in the Reference System Plan. One approach would be to develop a scoring system wherein staff would assign a score reflecting how well each portfolio addresses each state goal listed in Table 4.4. Each goal could potentially be assigned a weight reflecting its relative importance. Examples of this type of approach were presented publicly by IRP staff in 2016:

- Slides 55-64 of IRP Webinar #1 on Scenario Development in October 2016[31]
- Slides 36-51 of the scenario development slides prepared for the IRP workshop in December 2016[32]

Alternatively, staff could develop its recommendation in a more qualitative and holistic manner, evaluating the ability of different portfolios to achieve state goals without explicitly assigning numerical score or weight to each different goal. Parties are encouraged to comment on different possible approaches for how the final staff recommendation will be made (see Question 20 in the ruling).

It is important to note that the adopted portfolio itself will not constitute a specific procurement directive or authorization. It is possible that prices exposed during competitive solicitations or other procurement activities will differ from those assumed in modeling during development of the adopted portfolio. It may be in ratepayers' interest for LSEs to adjust procurement in response to actual market prices. The extent to which the specific quantities of resources identified in the adopted portfolio results are actually procured depends on several factors, which are explored in more detail in **Chapter 6**.

Question C: What investments or actions, if any, should be taken in the short term?

To answer the third primary question, staff will evaluate modeling results to determine their implications for specific resource types. In some cases, staff proposes additional, specialized model runs to supplement that information.

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[31] Available at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451365
[32] Available at:
http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/LTPP/IRP_Workshop_2016-12-16_ScenDev_rev.pdf

Based on its analysis, staff will make a recommendation as to whether any procurement or investment action by the CPUC or filing entities in the next 2-3 years is merited. In determining whether an action is merited, staff proposes as a starting point that the CPUC be guided by the principle of market efficiency:

- To the extent that the market can be reasonably expected to produce the desired outcome, there would be no reason for the CPUC to intervene.
- To the extent that there are material barriers to market solutions for any relevant market actors, the CPUC would act to address market deficiencies.

For example, the CPUC currently requires LSEs to acquire and/or pay for resources that meet reliability needs. This intervention is motivated by an understanding that market activity alone would not lead to an optimal amount of capacity available on the electricity system at an acceptable price. Staff invites parties to comment on the extent to which a market barrier exists for specific resource types and/or market actors (see Question 17c in the ruling). It is useful to consider, at a high level, what major barriers to market efficiency are generally understood to exist, and where the greatest and most significant uncertainties lie.

Staff proposes working with parties and other stakeholders throughout each IRP cycle to assess whether markets are functioning as expected and to determine how barriers may be addressed. Any actions that are deemed necessary to address market deficiencies will be included in the Action Plan section of the Reference System Plan. Please see the **Chapter 6** for additional information on the staff proposal for how the Action Plan would inform specific future actions by the CPUC, including procurement authorizations.

In developing its recommendations, staff proposes to answer three fundamental questions for each resource area:

C.1 Would an increase or decrease in procurement reduce overall costs, risks, or otherwise benefit state goals within the CPUC jurisdiction?

C.2 Is CPUC action necessary in the next 1-3 years given the lead time necessary to increase or decrease procurement?

C.3 Are there market, regulatory, or other barriers that would prevent the market from increasing or decreasing procurement without CPUC action?

Question C.3 is intended to explore what procurement activity requires new regulatory action by the CPUC or other entities, and what activity can be expected to take place as a result of market forces under current and expected regulations (i.e., will not require a specific IRP procurement or infrastructure authorization). Parties are encouraged to share their understanding of the barriers to market solutions for each resource and LSE type (see Question 17c in the ruling).

For some resources, there are specific, additional questions that staff proposes to address. These additional questions are listed under the heading “Special Study.” The questions that staff propose to address for each resource type are listed below.

- <u>Bulk Storage</u>
  - Is there a minimum level of bulk storage that is part of an optimal solution across a broad range of futures?
  - Does bulk storage reduce risk across a broad range of futures?
- <u>OOS Wind</u>
  - Is there a minimum level of out-of-state wind (with and without new transmission) that is part of an optimal solution across a broad range of futures?
  - Does OOS wind (with and without new transmission) reduce risk across a broad range of futures?
- <u>Geothermal</u>
  - Is there a minimum level of geothermal energy that is part of the optimal solution across a broad range of futures?
  - Does geothermal energy reduce risk across a broad range of futures?
- <u>Renewables</u>
  - Is there a minimum RPS level that is part of the optimal solution across a broad range of futures?
- <u>Battery Storage</u>
  - Is there a minimum level of storage that is part of optimal solution across a broad range of futures?
- <u>Behind-the-Meter Solar PV</u>
  - What are the impacts of higher levels of BTM PV adoption on costs, including customer costs?
- <u>Energy Efficiency</u>
  - What are the impacts of higher levels of EE adoption on costs, including customer costs?
  - Special Study: How does a GHG planning target affect the cost-effectiveness of EE measures?
    - Study Approach: Staff will directly use the marginal GHG abatement cost associated with the GHG constraint in RESOLVE to characterize the avoided

carbon abatement costs in one or more scenarios in the 2018 Energy Efficiency Potential and Goals (P&G) study.[33]

- The impact on EE potential of using the marginal GHG abatement cost generated by IRP will be captured within the P&G study itself. (A staff proposal describing an interim approach to using a GHG adder was introduced into the record of the IDER proceeding on April 3, 2017.)[34]

- Demand Response
    - Under what conditions do existing economic DR programs, new DR shed resources, and new DR shift resources (flexible loads), provide value?
- Electric Vehicles:
    - To what extent does EV charging flexibility affect costs?

    Special Study: What are the costs to the electrical system for different levels of decarbonization of the transportation sector? Can IRP provide information to the EV proceedings that can help inform cost-effectiveness and incentive levels as they relate to ZEV adoption and infrastructure authorizations?

[33] Refer to: http://www.cpuc.ca.gov/General.aspx?id=6442452619
[34] Available at: http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=182363230

Chapter 5: LSE Filing Requirements in IRP 2017-18

Chapter Summary

This chapter covers staff's proposal for what LSEs should include in the integrated resource plans that they file with the CPUC in the IRP 2017-18 cycle. Each LSE should file its Plan as an application to the CPUC. All IRP applications will likely be consolidated into a single proceeding for both individual and joint evaluation. Staff proposes that the CPUC organize IRP filing requirements based on the load forecast assigned to each LSE over the IRP planning horizon, with two categories of LSE Plans: Standard LSE Plan and Alternative LSE Plan. Standard Plans would be required for LSEs whose assigned load forecast is ≥ 700 GWh in any of the first five years of the IRP planning horizon, and all other LSEs may file an Alternative Plan. Minimum requirements will be established for content and data format for each category of IRP. For Alternative Plans, staff proposes a simplified review process; for Standard Plans, staff proposes to review each LSE Plan both individually and in aggregate. Whether the plans pass individual review and aggregate review would determine the appropriate action by CPUC.

Filing Process

Staff proposes that the CPUC set a common date on which all obligated LSEs shall file their integrated resource plans. Each Plan would be filed as an application to the CPUC by the individual LSE. The intent would be to consolidate all of the IRP applications into a single proceeding so that they may be considered both individually and together. It is possible that groups of different types of LSE plans might be consolidated together rather than all IRPs. For example, all IOUs could be considered together, separate from CCAs, who would in turn be separate from ESPs. The CPUC can give more formal guidance on the exact procedural approach in the future.

One major advantage of separate applications that are consolidated is that the CPUC can keep the IRP rulemaking as a quasi-legislative proceeding that considers and sets forward-looking policy, while the IRPs can be ratesetting (with the associated *ex parte* and other rules associated with such proceedings),[35] since there likely will be real costs associated with approval of at least some of the IRPs and incremental procurement authorized by the Commission for individual entities.

Consolidating applications also will allow the IRPs to be considered together, with individual LSEs able to compare across multiple entities, and respond to each other's IRP filings. The CPUC would likely set a single date for responses to all IRPs, with enough time for the large number of IRPs to be considered (i.e., a longer response period than most single applications to the CPUC).

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[35] The CPUC's practitioners' guide to ex parte communications is available at: docs.cpuc.ca.gov/PUBLISHED/REPORT/124510.htm.

Types of LSE Plans Recognized by the CPUC

By law, all LSEs must file an integrated resource plan (LSE Plan) with the CPUC. Staff proposes that the CPUC recognize two categories of LSE Plans: Standard and Alternative. This section details the proposed criteria for determining which type of Plan an LSE must file. The content required in Standard and Alternative LSE Plans is defined in the sections below.

IRP Filing Requirements Should Be Based on Load

Staff proposes that the type of LSE Plan an LSE is eligible to file depends on the load it is forecast to serve over the IRP planning horizon. The CPUC will initially assign a load forecast for the IRP planning horizon to each LSE, except ESPs, using the mid AAEE version of Form 1.1c of the latest IEPR demand forecast.[36] ESPs must submit the load they propose to plan for in their LSE Plan (see next section below). The load forecast assignment provides an initial direction as to which plan type an LSE may be eligible to file, and staff proposes that LSEs be required to use this load forecast in developing their plans.

If the load forecast assigned to an LSE is ≥ 700 GWh in any of the first five years of the IRP planning horizon, then staff suggests the LSE file a Standard Plan. If the load forecast assigned to an LSE is < 700 GWh in any of the first five years of the IRP planning horizon, the LSE may be eligible to file an Alternative Plan (see Table 5.1).

Staff also suggests that the LSE's preferred portfolio be required to reach the assigned GHG target and/or clearly use the designated GHG abatement cost (refer to **Chapter 3** for the proposed methodology for calculating the GHG abatement cost).

Table 5.1. Preliminary Plan Designation for CPUC-Jurisdictional LSEs. An LSE's filing eligibility may change depending on subsequent load assignments and/or LSE-submitted documentation validating its eligibility.

LSE Type	LSE Name*	Balancing Authority Area	LSE Plan Designation
Large IOU	Pacific Gas and Electric	CAISO	Standard
	Southern California Edison	CAISO	Standard
	San Diego Gas and Electric	CAISO	Standard
CCA	CleanPowerSF	CAISO	Standard
	Lancaster Choice Energy	CAISO	Alternative
	Marin Clean Energy	CAISO	Standard
	Sonoma Clean Power	CAISO	Standard
Small IOU	Bear Valley Electric Service	CAISO	Alternative
	Liberty Utilities	NV Energy	Alternative
Multi-Jurisdictional IOU	PacifiCorp	PacifiCorp West	Alternative**

[36] The appropriate form can be found online at: http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-05/TN216264_20170227T144018_Corrected_LSE_and_BA_Tables_Mid_Baseline__Mid_AAEE.xlsx.

Electric Cooperative	Anza Electric Cooperative Inc.	CAISO	Alternative
	Plumas-Sierra Electrical Cooperative	CAISO	Alternative
	Surprise Valley Electrical Corp.	PacifiCorp West	Alternative
	Valley Electric Association, Inc.	CAISO	Alternative
ESP	3Phases Renewable Energy LLC	CAISO	TBD
	Agera Energy, LLC	CAISO	TBD
	Calpine Power America CA, LLC	CAISO	TBD
	Commerce Energy Inc.	CAISO	TBD
	Commercial Energy of California	CAISO	TBD
	Constellation New Energy Inc.	CAISO	TBD
	Direct Energy Business LLC	CAISO	TBD
	EDF Industrial Power Services, LLC	CAISO	TBD
	Gexa Energy California, LLC	CAISO	TBD
	Glacial Energy of California, Inc.	CAISO	TBD
	Liberty Power Holdings	CAISO	TBD
	Next Era Energy	CAISO	TBD
	Pilot Power Group	CAISO	TBD
	Sempra Energy Solutions LLC (Noble Energy)	CAISO	TBD
	Shell Energy North America	CAISO	TBD
	The Regents of the University of California	CAISO	TBD
	Tiger Natural Gas Inc.	CAISO	TBD

*This list is not exhaustive and may exclude the names of several ESPs; notwithstanding, IRP filing requirements do apply to all CPUC-jurisdictional LSEs.

**Although PacifiCorp has served load inside California, because it has not served load inside of CAISO in the past three years, it may be eligible to file an Alternative Plan. See "Alternative LSE Plan Requirements" below for details.

Process for Finalizing Load Assignments

All ESPs, and any LSE wishing to plan for a different load than it was initially assigned, must include as part of their comments on this staff proposal the following information:

- Proposed LSE load for each year of the IRP planning horizon;
- Quantitative assessment of how the proposed load is expected to affect the assigned load of all other LSEs; and
- Explanation of why it is reasonable for the LSE to plan for that load level.

Parties may offer comment on proposed load assignments. The Commission is expected to provide direction regarding the disposition of the LSE load assignments in its decision adopting the IRP process. All eligibility requirements will then apply to the new load assignments.

IRP Requirements

In order to expedite the timely and fair review of the IRPs received from its jurisdictional LSEs, staff proposes establishing minimum requirements for each category of IRP that is officially recognized (Standard and Alternative). Under this approach, the CPUC would not approve or certify any IRP submitted to the CPUC that does not satisfy the requirements described below.

Box 5.1 Linkages between Reference System Plan and LSE Plans

The Reference System Plan will include the Reference System Portfolio, Reference System Action Plan, and specific guidance for what information must be used by LSEs in the development of their own LSE Plans. Appendix D itemizes the data files CPUC staff will use to describe the Reference System Portfolio. LSEs are expected to describe their portfolios using a similar format that is specified in Appendix C, the Standard LSE Plan Template. The intent is that LSEs are effectively receiving the Reference System Portfolio in a standard format, and then transmitting its LSE portfolio back to the CPUC in a similar format but tailored to be LSE-specific. While LSEs must only plan for their own assigned loads, LSE Plans must reflect the following major aspects of the Reference System Plan:

1. The LSE guidance part of the Reference System Plan will specify at least one scenario, along with associated assumptions including a GHG Planning Price, that each LSE must represent in developing its own LSE portfolio. (LSEs may also study and report alternative portfolios developed from additional scenarios that have different assumptions from the Reference System Plan. LSEs select their preferred portfolio from among all the portfolios it developed.)

2. An LSE should only be modifying the portion of the Reference System Portfolio that it needs to serve its own load. The rest of the Reference System Portfolio acts as a common basis for the LSE to consider the interactive effects of an LSE's portfolio choices with the rest of the system.

3. LSE Plans must also include a narrative description of how their plans account for the effect of potential procurement by other LSEs, POUs, and merchant generators assuming that such procurement is, in aggregate, consistent with the Reference System Plan.

Standard LSE Plan Requirements

Staff proposes two types of Standard Plan Requirements: general requirements and technical requirements. General requirements outline the required format and content of an LSE Plan. Technical requirements provide more detailed, often quantitative guidance, on specific assumptions that must be used to develop the LSE Plan.

All requirements are described in more detail below. Some of the technical requirements will not be available until the Reference System Plan is adopted by the CPUC. Such requirements are clearly identified in the descriptions below. A draft IRP filing template reflecting these requirements is provided in **Appendix C**. LSEs preparing a Standard Plan will be expected to use this template. To the extent that information within individual LSEs' integrated resource plans are not market-sensitive and confidential, those materials will be made publicly available.

General Requirements

Staff proposes that a Standard Plan include, at a minimum, six sections: Executive Summary, Study Design, Study Results, Action Plan, Resource Valuation Methodology, and Data. The Data section would include Excel workbook(s) as separate attachment(s) with data conforming to the requirements described below and in Appendix C. An outline of the content for each of the required sections is provided below.

1. Executive Summary: This section will summarize the LSE's IRP process, outline the LSE's major findings, and provide an overview of the LSE's preferred portfolio and proposed next steps.
2. Study Design: This section will describe how the LSE approached the process of developing its LSE Plan. It includes the following sections:
    a. Objectives: a description of the LSE's objectives for the analytical work it is documenting in the IRP.
    b. Methodology: the process through which the LSE developed its Plan, including:
        i. Modeling tool(s), if modeling used
        ii. Modeling approach, if modeling used, including description and rationale for the cases modeled
        iii. Description of any post-processing used to generate metrics for portfolio analysis
    c. Assumptions: documentation of any assumptions that differ from those used by CPUC to develop the Reference System Plan
        i. Includes side-by-side comparison to CPUC assumptions, rationale for the differing assumption, explanation of how the assumption was developed and/or calculated, and citation to sources of data
        ii. Numerical data is reported according to the requirements itemized below under "Data" and in Appendix C
3. Study Results: This section will present the results of the analytical work described in the previous section. It includes:
    a. Portfolio Results: A list of all portfolios developed, along with required summary metrics (including quantitative and any qualitative information). The required metrics will be specified in the Reference System Plan.
    b. Preferred Portfolio: Identification of Preferred Portfolio & Rationale. The rationale includes an explanation of how the preferred portfolio is consistent with all state goals listed under Question B.4 in **Chapter 4** of this proposal, including the prioritization of air pollutant reduction in disadvantaged communities. Rationale should also include an analysis of how the preferred portfolio accounts for potential procurement by other LSEs, assuming other LSEs procure in a manner consistent with the Reference System Plan.

i. Disadvantaged Communities: Describe and provide quantitative evidence to support why the LSE's preferred portfolio is consistent with all statutory requirements and CPUC policy regarding disadvantaged communities.

ii. Cost Analysis: Describe and provide quantitative information to reflect how the LSE anticipates that the LSE's preferred portfolio will affect the costs for the LSE's own ratepayers as well as other ratepayers in CAISO. For this analysis, assume other LSEs procure resources in a manner consistent with the Reference System Plan.

iii. Risk Analysis: Describe the risks to the LSE and the LSE's ratepayers associated with any failures on the part of other LSEs to procure resources consistent with the Reference System Plan. Provide quantitative evidence wherever possible.

c. Deviations from Reference System Plan: Explanation and justification for any major deviations in the proportional distribution of resource types between the Preferred Portfolio and the Reference System Portfolio.

d. Deviations from Current Resource Plans: Explanation of any major deviations between the LSE Plan and any current resource plans, including RPS Plans, Bundled Plans, Energy Efficiency Business Plans, Energy Efficiency Implementation Plans and any pending applications.

e. For LSEs that serve load within a CAISO-defined local capacity area: Report the LSE's own assessment of annual incremental local capacity resource needs for the entire local capacity area if it differs from the most recent transmission plan adopted by the CAISO governing board.[37]

4. Action Plan: This section will present all the actions that the LSE proposes to take in the next 1-3 years to implement its LSE Plan. It includes:

   a. Proposed Activities: Activities for all resource areas, including opportunities for process alignment across resource areas and how the LSE anticipates that alignment will occur at their organization (similar to process alignment activities expected to occur at CPUC, which are addressed in **Chapter 7**)

   b. Barrier Analysis: Identification of any market, regulatory, financial, or other barriers or risks associated with acquiring the resources identified in the preferred portfolio

   c. Proposed Commission Direction: Describe any direction that the LSE seeks from the CPUC, including any new spending authorizations, changes to existing authorizations, or

[37] CAISO has ten primary local capacity areas (i.e. transmission-constrained load pocket): Humboldt, North Coast North Bay, Sierra, Stockton, Greater Bay, Greater Fresno, Kern, LA Basin, Big Creek Ventura, San Diego Imperial Valley

changes to existing programmatic goals or budgets. Clearly relate any requested direction to the study results, proposed activities, and barrier analysis presented above.

   d. Lessons Learned: Document any suggested changes to the IRP process for consideration by the CPUC. Explain how the change would facilitate the ability of the CPUC and LSEs to achieve state policy goals.

5. Common Resource Valuation Methodology: This section will describe how the LSE will consistently value different resources of all types (not only renewables) and evaluate bids in solicitations. Proposals for development of a common resource valuation methodology will be solicited from parties at a later date (see **Chapter 6** for more information). The LSE's methodology must account for:
   a. Consistency across all resource types
   b. Potential changes in resource value due to future procurement activity by other LSEs that share the CAISO grid
   c. Costs and benefits to and for disadvantaged communities

6. Data: This section will consist of all required data including information described in the preceding sections. Data provision must conform to the data template included with Appendix C. Any supplemental or supporting data incremental to the fields in the data templates shall also be reported, but in separate files. Data reporting must meet the following requirements:
   a. For EACH portfolio considered by the LSE, create a file "Data_LSEname_Portfolioname_yyyymmdd.xlsx" using the data template and complete all fields.
      i. The file name must follow the naming format above, where the field "LSEname" is replaced with the LSE name (e.g. "MCE" or "PGE"), the field "Portfolioname" is replaced with the LSE's unique name for the portfolio, and "yyyymmdd" is replaced with the date the file is submitted to the CPUC.
      ii. Spaces are not allowed in the file name. Special characters are not allowed, except for underscore ("_") and dash ("-").
      iii. The data template includes a worksheet with instructions and multiple worksheets to be filled out by the LSE. The worksheets ask for the following types of information:
         1. The portion of the Reference System Portfolio that the LSE intends to use (own or contract with) to serve its assigned load level over the IRP planning horizon. If the resources the LSE intends to use (including new resources that the LSE selected for its portfolio) fall short of the capacity and energy needed to serve LSE load over the IRP planning horizon, it will be assumed that the LSE intends to procure generic capacity and energy on the market.

2. A list of new resources that the LSE selected for its portfolio. Each resource must be mapped to a RESOLVE resource or portion of a RESOLVE resource the LSE selects to match with or replace.

3. The LSE's projection of fixed costs from the LSE's existing investments.

4. The LSE's projection of fixed costs from the list of new resources that the LSE selected for its portfolio, including fixed costs from any new transmission necessitated by the LSE's selected new resources .

5. The LSE's annual peak load and average energy forecast including any impacts from load modifying resources.

iv. Each worksheet includes data validation that requires the LSE to populate cells with only allowed values.

v. Cells must contain only text or numerical data. Any comments about certain cells or rows shall be made in the text body of the primary LSE Plan report, not in the data template.

b. In rare instances, the LSE may need to report supplemental or supporting data incremental to the fields in the data template described above. An example is where the LSE used a set of assumptions to develop a portfolio that differs from the corresponding set of assumptions used to develop the Reference System Plan, and those assumption differences are not captured in the required data template above. The requirement to report assumptions differences was stated above as required content for the "Study Design" section of an LSE Plan. The numerical data for such differences shall be reported in separate Excel-compatible workbooks and follow these requirements:

i. For EACH portfolio considered by the LSE that requires supplemental or supporting data, report the data in a file "Diff_LSEname_Portfolioname_yyyymmdd.xlsx" and follow the same file naming convention described above for the data template file.

ii. For each differing assumption include a side-by-side comparison of the original assumption data from the Reference System Plan and the LSE's differing assumption data.

iii. Explanations for each difference shall be made in the text body of the primary LSE Plan report, not the Excel workbook.

Technical Requirements

The technical requirements listed below provide more detailed, often quantitative guidance on specific assumptions that must be used to develop the Standard LSE Plan.

Assumptions

In general, the LSE Plan should be based on the same assumptions used to develop the Reference System Plan, with the exception that the LSE Plan need only reflect resources needed to serve the LSE's assigned load. If an LSE wishes to use different assumptions, those assumptions must be clearly documented as described under General Requirements above.

Scenarios

The Reference System Plan will specify at least one scenario that all LSE Plans must include. LSEs may also include additional scenarios of interest, but must clearly specify the assumptions used to define each scenario. See also, Box 5.1 above.

Assigned Load

The LSE must develop its Plan to serve the load level assigned to the LSE by the CPUC over the IRP planning horizon. Refer to Form 1.1c of the most recent IEPR demand forecast for initial guidance on the assigned load levels for all LSEs except for ESPs. Final load assignments will be included in the decision adopting the IRP Reference System Plan.

Resources For Assigned Load

The LSE must document each RESOLVE resource or portion of a RESOLVE resource that it plans to use (own or contract with) to serve its assigned load level over the IRP planning horizon. This includes from both the baseline inventory of existing and planned resources in the Reference System Portfolio, and the new resources the LSE selects in its Plan. Each LSE resource must be matched to a RESOLVE resource name, e.g. CAISO_Aero_CT, CAISO_Li_Battery, or Greater_Carrizo_Solar. If the resources in the LSE Portfolio fall short of the capacity and energy needed to serve LSE load over the IRP planning horizon, it will be assumed that the LSE intends to procure generic capacity and energy on the market.

GHG Planning Price

LSEs must use the GHG Planning Price assigned by CPUC (refer to **Chapter 3**) when calculating the costs of the portfolios included in the LSE Plan.

GHG Accounting

Filing entities should apply standard fuel emissions factors for estimating GHG emissions associated with known resources or market purchases in their portfolios. For estimating GHG emissions from unspecified power, the portfolio should use CARB's default emissions factor of 0.428 MT of CO_2e/MWh (943 lbs/MWh).

Unspecified Power

There is no limit to the amount of unspecified power that an LSE may include in its plan.

IRP Planning Horizon

The IRP planning horizon for the first IRP cycle is 2018-2038 (20 years).

Resource Types

A table should be provided that maps each energy resource type included in any portfolio to the corresponding RESOLVE resource types (e.g., a combined cycle plant should be mapped to the RESOLVE resource type "Gas - CCGT"). Additional and more granular categories may be used.

Rates (IOUs only)

Data must be provided showing the forecasted revenue requirement and average rate for bundled customers over the IRP Planning Horizon for any scenarios required in the Reference System Plan.

The data should reflect at least three load forecasts:

- Assigned load
- 50% of assigned load
- 10% of assigned load

The data should include revenue requirements for each portfolio, broken down by the following categories:

- Transmission
- Distribution
- DSM Programs
- Generation
- Other

In presenting revenue requirement data, IOUs should clearly distinguish between spending already authorized, spending currently under review by the CPUC (including any authorizations sought through the IRP application), and spending not yet submitted to the CPUC. IOUs should assume no procurement on behalf of non-bundled customers would be needed.

Alternative LSE Plan Requirements

Staff proposes that the CPUC recognize two types of Alternative LSE Plans. The CPUC would only review Type 1 LSE Plans submitted by eligible small IOUs, ESPs, CCAs, and Cooperatives. The CPUC would only review Type 2 LSE Plans submitted by eligible MJUs. The proposed requirements for each type of Alternative LSE Plan are listed below.

Type 1 Alternative LSE Plan

1. Eligible LSEs: Small IOUs, ESPs, CCAs, and Electric Cooperatives

2. Requirements: The CPUC assigns a load of <700 GWh in first five years of planning horizon.
    a. If Electric Cooperative does not have an all-requirements contract: no additional information required
    b. If Electric Cooperative does have an all requirements contract:
        i. Annual capacity and energy provided via all requirements contract
        ii. CEC Power Content Report
        iii. Copy of all requirements contract
    c. A demonstration of how disadvantaged communities are being considered

Type 2 Alternative LSE Plan

1. Eligible LSEs: MJUs
2. Requirements: The LSE may submit any IRP submitted to another public regulatory entity within past year. If this IRP does not already include a demonstration of how disadvantaged communities were considered, a separate demonstration must be submitted.

Standard of Review for LSE Plans

For Alternative Plans, staff proposes that the review process consist of verifying the LSE's eligibility to file an Alternative Plan and that the submitted IRP meets the relevant requirements. For Standard Plans, Energy Division staff, including the Energy Resource Modeling group, would review each LSE Plan both individually and in aggregate, as described in the steps below.

1. Verify all required sections are present, and each section includes all required components, as itemized above under General Requirements and Technical Requirements.
2. Verify all required types of data are provided and data meets the format requirements, as described above in the Data section listed under General Requirements.
3. Aggregate all the LSE-preferred portfolios into one system portfolio that may be compared to the Reference System Portfolio.
4. Populate a production cost simulation model with the aggregate of all the LSE-preferred portfolios.
5. Perform production cost simulations to validate the operational performance (e.g. emissions, reliability level, operating cost) of the aggregate portfolio, and compare to corresponding results with the Reference System Portfolio.
    a. Staff proposes to test annual and/or monthly metrics for select target years. Standard reliability metrics include Loss of Load Expectation, Loss of Load Hours, and Expected Unserved Energy.

b. Staff proposes to use the same production cost modeling analytical tools that staff used to calculate Effective Load Carrying Capability in the current Resource Adequacy proceeding (R.14-10-010).[38] Staff proposes to follow the production cost modeling standards specified by ALJ Ruling in the IRP-LTPP proceeding (R.16-02-007),[39] except that the modeling will use the assumptions and portfolios of the aggregate of the LSE-preferred portfolios or the Reference System Portfolio.

c. The exact scope of the production cost modeling (e.g. annual vs. monthly, target years, reliability metrics) will be included with the CPUC adoption of the Reference System Plan.

6. Evaluate each individual LSE's emissions level based on the portfolio it plans to use (own or contract with) plus its market purchases to serve its assigned load level over the IRP planning horizon. This portfolio includes resources from both the CAISO-wide baseline inventory of existing and planned resources, and the new resources the LSE selects as mentioned above under Technical Requirements, Resources For Assigned Load.

Outcomes of Review

Staff proposes that if all plans pass the standards of review described above, then the CPUC will direct the actions described in next chapter of this proposal. If any LSE plan fails the review process, the filing entity will be advised of the deficiency and given an opportunity to submit a corrected LSE Plan.

Box 5.1. Filing Requirements Related to DAC

The results of the analysis detailed in Chapter 4, Section "How DAC Issues will be Addressed in Preparing the Reference System Plan," will inform the development of LSE filing requirements related to DAC. The release of these results, which will inform the development of metrics to account for the costs and benefits of prioritizing DACs, will be followed by a workshop to help determine the appropriate cost and benefit metrics by which the CPUC will assess how LSEs have considered disadvantaged communities in their plans.

In order to identify "disadvantaged communities," staff proposes that each LSE use CalEnviroScreen 3.0 to identify both the top 25% of impacted census tracts in California that are located within its service territory, as well as the top 25% of impacted census tracts solely within its service territory. Both calculations are expected to be demonstrated in an LSE's Plan, and the LSE would then use the broader of the two options to identify disadvantaged communities for use in its Plan. All LSEs will be expected to consider disadvantaged communities as part of their Plans by assessing air quality impacts of portfolios

[38] http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=10599
[39] Refer to: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451199

and seeking approval of a plan that minimizes air quality impacts while taking into consideration relative cost based on the abovementioned to-be-established metrics.

Chapter 6: Procurement, Compliance, and Cost Recovery

Chapter Summary

The preceding chapters describe staff's proposal for the planning activities involved in the IRP process. This chapter describes staff's proposed approach for how IRP planning activities would inform procurement and cost recovery in the 2017-18 cycle and beyond. Procurement is defined for the purposes of the IRP process as any formal or informal activity by the CPUC or CPUC staff that is intended to directly or indirectly affect the development and acquisition of new[40] supply- or demand-side energy resources by LSEs or LSE customers.

Whereas planning activities highlight potential future challenges and opportunities, procurement activity, as defined above, is the means through which the electric sector can actually achieve measurable state goals, including greenhouse gas reduction and reliable electric service at just and reasonable rates. Because procurement is the actual basis for achieving state goals, it is also the primary activity that must be monitored and evaluated by the CPUC.

This chapter addresses different regulatory options for ensuring that procurement activity is in compliance with the planning goals established in the Reference System Plan, LSE Plans, and Preferred System Plan. Staff proposes two checkpoints during each IRP cycle for the CPUC to evaluate and decide on whether to initiate procurement-related activity: first when the Reference System Plan is released, and again when the Preferred System Plan formally replaces the Reference System Plan. Staff describes three potential approaches to IRP-based procurement and lists various discrete policies that could be added to those approaches. For the IRP 2017-18 cycle, staff proposes the following:

- IRP generates information about the optimal portfolio and develops a GHG Planning Price, and it evaluates procurement needs under circumstances that include, but are not limited to, the following:
    - If long-term reliability needs that require new investment are clearly identified, or unexpected short-term reliability needs arise, the IRP proceeding will contemplate authorizing or directing procurement to satisfy those needs.

[40] Staff recognizes that LSEs also procure electricity from existing resources, but for purposes of IRP, the procurement emphasis is on procuring new resources that are planned for as part of the IRP analysis.

- A new track or proceeding may be opened to further explore any capital intensive, long-lead time resources (e.g., OOS wind, large-scale pumped hydro, etc.) that IRP analysis indicates is likely to be beneficial.
- If the GHG reduction target adopted for the electric sector requires new investment in zero carbon energy, IRP may consider recommending accelerating the date by which 50% RPS must be achieved.
- If the quantity of short duration storage in the adopted portfolio differs from what regulated LSEs are currently required and/or authorized to procure, IRP will consider recommending changing the storage procurement target (higher or lower).
- If the quantity of distributed energy resources in the adopted portfolio, including energy efficiency, demand response, and behind-the-meter solar PV differs from the quantities anticipated to result from existing Commission policies, IRP will consider recommending changes to the affected program rules, funding levels, and/or goals.

- IRP provides a GHG Planning Price for use in cost-effectiveness tests in the IDER proceeding (R.14-10-003) and EE proceeding (R.13-11-005).
- IRP coordinates with the RPS proceeding to produce a common resource valuation methodology that can be applied across all resources, establishing a clear link between planning and procurement.

Staff acknowledges that IRP-based procurement approach is likely to change over time based on program feedback and lessons learned. Staff also addresses expectations for cost allocation and recovery for new resources proposed to be procured by the IOUs.

- If the need is for local reliability, staff recommends the costs of individual procurement to be covered by all customers in the corresponding IOU territory in accordance with the existing cost allocation mechanism.
- If a need for additional flexible or system resources is identified, staff recommends that the CPUC apply the cost allocation mechanism framework on a system-wide basis.
- If the CCAs and ESPs submit Plans that meet reliability and GHG reduction requirements at the LSE level, and CPUC has identified a reasonable approach to allocating responsibility for any deficiencies in the aggregated LSE Plans (see Question 33b, 33c, and 33d in the ruling), then staff recommends that only IOU bundled ratepayers cover the costs of additional IOU procurement identified in the individual IOU Plans.

Procurement Checkpoints

As stated in **Chapter 4**, in determining whether to authorize new procurement, program funding, or tariff changes, staff proposes that the CPUC be guided by the principle of market efficiency. To the extent that the market can be reasonably expected to produce the desired outcome, there would be no reason for the CPUC to intervene. To the extent that there are material barriers to market solutions for relevant market actors, the CPUC must address those barriers through regulatory action that directly or indirectly affects investment in generation, transmission, and/or or distributed energy resources..

Staff proposes two checkpoints during the IRP process for the CPUC to evaluate and decide on whether to initiate or trigger procurement activity. Procurement is defined for the purposes of the IRP process as any formal or informal activity that is intended to directly or indirectly affect the development and acquisition of new supply- or demand-side energy resources by LSEs or LSE customers. It is important to distinguish IRP procurement, which refers to the acquisition of new resources, from the resource adequacy procurement construct, which typically involves securing contracts with existing resources.

IRP procurement activities include, but are not limited to:

- new proceeding, track, or staff-level activity to further evaluate a specific resource type (e.g., OOS transmission or bulk storage);
- recommended changes to the targets or rules of existing resource programs (e.g., RPS, storage, etc.)
- authorizations to hold attribute-specific, location-specific, or all-source solicitations;
- recommended changes to authorized program funding levels (e.g., energy efficiency); and
- recommended changes to CPUC program tariffs (e.g., Net Energy Metering Successor Tariff).

The first proposed procurement checkpoint occurs when the Reference System Plan is released. The Reference System Plan will include an Action Plan listing potential actions that are substantiated by Energy Division staff analysis. At this checkpoint, the CPUC's IRP actions would be limited to activities that do not involve authorizing new spending, such as initiating a new proceeding or track to further evaluate a specific resource type.

The second proposed checkpoint occurs when the aggregated LSE Plans are approved and the Preferred System Plan replaces the Reference System Plan. At this checkpoint, the CPUC may initiate any procurement-related activity, for any resource type, including authorizing new spending. The CPUC may also transfer portfolios to the CAISO or other transmission planning entity for the purpose of authorizing policy-driven transmission needs.

The remainder of this chapter presents more specific options for the types of procurement-related activities that the CPUC would undertake at the second checkpoint, in addition to staff's proposal for IRP-based procurement in the 2017-18 cycle.

Potential Approaches to IRP-Based Procurement and Compliance

Whereas planning activities highlight potential future challenges and opportunities, procurement activities, as defined above, are the means through which the electric sector can actually achieve measurable state goals, including greenhouse gas reduction and reliable electric service at just and reasonable rates. Because procurement is the actual basis for achieving state goals, it is also the primary activity that must be monitored and evaluated by the CPUC.

Three idealized approaches to IRP-based procurement and compliance are described below. Each approach represents a different fundamental relationship between planning and procurement.

1. **Informational**: IRP produces information but does not directly affect individual resource mandates, except for resources needed for reliability purposes. Procurement decisions and compliance continue to be adjudicated in individual resource-specific proceedings. Compliance is based on primarily on procurement of specific types of resources, not GHG emissions.
2. **Resource Target Setting**: IRP sets binding targets for each resource area (e.g., RPS target, storage target, EE goals, DR goals, EV infrastructure budget) based on the Reference System Plan and the Preferred System Plan. Resource-specific program rules continue to be set through existing resource-specific proceedings, and compliance continues to be adjudicated through individual program rules in resource-specific proceedings. Compliance is based on procurement of specific types of resources, not GHG emissions.
3. **GHG Target Setting**: IRP transitions fully away from prescriptive resource targets and instead allows LSEs flexibility to meet load-based GHG emissions planning targets. IRP would develop a new, umbrella procurement program that supersedes all other resource-focused programs, and would ensure that LSE portfolios achieve GHG planning targets, which could be expressed as a tolerable range of mass-based emissions or a target emissions intensity. This approach differs from the source-based compliance regime of CARB's Cap and Trade Program. Procurement planning and review would be based primarily on each LSE demonstrating its ability to meet its GHG emissions planning target, rather than meeting specific resource targets.

Individual Policies

It may be possible to apply one of the broad approaches listed above to one type of resource, and another approach to a different type of resource. In addition, there are cross-cutting policies that could shape the way that the CPUC administers procurement-related activities. Below is a list of discrete policies that could potentially be individually added to one or more of the three broad procurement approaches.

Policies Affecting All Resources

1. **Common Resource Valuation Methodology (CRVM)** – a standardized methodology for evaluating different resources that the CPUC could require be used across all resource areas. This methodology could include prescribed approaches for considering the impact of procurement outcomes on disadvantaged communities.

Policies Affecting Specific Resource Types

2. **Joint Procurement Trigger** – if justified by IRP analysis, open a new proceeding (or a new track in IRP) to explore the possibility of mandating or facilitating procurement of large, capital-intensive, long lead time projects (e.g., bulk storage, OOS wind + transmission, or geothermal)
3. **RPS Target Only** – CPUC sets the RPS target to a new level, e.g., something greater than 50% by 2030, based on IRP analysis
4. **Storage Target Only** – CPUC sets a storage target based on IRP analysis
5. **GHG Planning Price Only** – CPUC requires use of GHG Planning Price in cost-effectiveness tests
6. **EE Goals Only** – CPUC sets new or different EE program goals based on IRP analysis
7. **IRP-Driven NEM 3.0** – set tariffs and incentives consistent with value of rooftop PV in IRP analysis
8. **IRP-Driven DER Tariffs** – set tariffs to affect growth of DERs consistent with IRP analysis
9. **Replacement Authorization** – CPUC determines need and authorizes procurement for replacing retiring resources, e.g., Diablo Canyon, or unexpected new needs

CPUC and/or Statutory Reforms

10. **Electric Program Investment Charge (EPIC) Program[41] Reform** – CPUC and/or CEC use IRP results to prioritize EPIC Program funding
11. **Power Charge Indifference Adjustment (PCIA)[42] & Cost Allocation Mechanism (CAM)[43] Reform** – allocation of costs for all departing load and new procurement; all LSEs exposed to full costs of their own decisions
12. **Recommended Statutory Changes** (e.g., remove requirement that RPS % be equivalent for all regulated entities)

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[41] The EPIC Program was created by the CPUC in December 2011 to support investments in clean energy technologies that provide benefits to the electricity ratepayers of PG&E, SDG&E, and SCE. The EPIC program funds clean energy research, demonstration and deployment projects that support California's energy policy goals and promote greater electricity reliability, lower costs, and increased safety. More information is available at: http://www.energy.ca.gov/research/epic/.

[42] Public Utility Code Sections 365.1, 365.2, 366.1, 366.2, and 366.3 require the CPUC to ensure that customers leaving an IOU, e.g., for a CCA, do not burden remaining utility customers with costs which were incurred to serve them. To ensure this "customer indifference," CCAs and direct access customers are required to pay a PCIA.

[43] CAM is a regulatory process for allocating capacity costs of utility procurement across all benefitting customers. More information is available at: http://www.cpuc.ca.gov/General.aspx?id=6949.

Hybrid Procurement Approaches

Below are examples of possible combinations of the three primary procurement approaches with individual policy options. The numbers preceding each combination listed below are provided as a convenience to more easily distinguish among them.

1. Informational

1.1 Informational + Uniform CRVM

1.2 Informational + Uniform CRVM + Joint Procurement Trigger

1.3 Informational + Uniform CRVM + Joint Procurement Trigger + GHG Planning Price

2. Resource Target Setting

2.1 Target Setting + Uniform CRVM

2.2 Target Setting + Uniform CRVM + Joint Procurement Trigger

2.3 Target Setting + Uniform CRVM + Joint Procurement Trigger + Recommended Statutory Changes

3. GHG Target Setting

3.1 GHG Target Setting (including Uniform CRVM) + Recommended Statutory Changes (e.g., LSE-specific RPS targets)

Procurement Approaches May Change over Time

IRP-based procurement may begin with the approach that is the most feasible to implement in the first cycle and, if justified based on program feedback and lessons learned, gradually evolve into one that includes larger regulatory changes by 2023.

The informational approach would be the simplest to implement in the short term. Under this approach, the Reference System Plan, LSE Plans, and Preferred System Plan developed through the IRP process would serve as resources that will inform procurement decisions in resource-specific proceedings, but they would not be the direct basis for CPUC decisions that change the levels of mandated resources for other programs. Incremental procurement may be authorized, but CPUC decisions directing resource-specific procurement would continue to take place in the context of resource-specific proceedings, such as RPS. Resource-specific decisions may follow the direction provided by IRP, but may also deviate from that direction.

A target-setting approach, while more complex to implement than the first approach, would work through existing regulatory mechanisms that are familiar to LSEs. A target-setting approach for many resource types, particularly DERs, is more likely to be in reach for IRP starting in 2019. By that time, further development of location-specific cost and potential data for a variety of DERs and non-DER grid integration solutions, as well as the development of new modeling resources, could enable IRP to more directly compare the costs and benefits of demand and supply resources for achieving state goals.

To be effective, the third approach—procurement freed from resource targets and focused primarily on achieving electric sector GHG reductions at least cost—is likely to require substantial reform of CPUC policies and potentially statutory changes as well. For example, current statute requires the CPUC to set a uniform RPS target for all LSEs. A uniform RPS target could be a disincentive to an LSE wishing to pursue transportation electrification investments that would otherwise be a cost-effective way to achieve state GHG and air pollution reduction goals. Alternatively, or additionally, a new, tradeable, load-based GHG reduction instrument for use only within the electric sector could be used to facilitate economically efficient and enforceable compliance program. Such a program would run a high risk of being confused with CARB's Cap and Trade program, and could create major regulatory complexity.

An example for a potential sequencing of IRP procurement policy over time is provided below:

- 2017-18: 1.3 Informational + Uniform CRVM + Joint Procurement Trigger + GHG Planning Price + RPS Target, if justified by Reference System Plan
- 2019-20: 2.2 Resource Target Setting + Uniform CRVM + Joint Procurement Trigger
- 2021-22: 2.2 Resource Target Setting + Uniform CRVM + Joint Procurement Trigger
- 2023-24: 3.1 GHG Target-Setting + Joint Procurement Trigger

The first bullet reflects staff's recommendation for IRP-based procurement in the 2017-18 cycle, as described below.

A Hybrid Approach to Procurement in IRP 2017-18

For the IRP 2017-18 cycle, staff proposes a hybrid approach to procurement, whereby the IRP process informs procurement decisions in resource-specific proceedings but does not specifically direct individual resource procurement or infrastructure investment, with three notable exceptions. Specifically, IRP may be used to authorize procurement or investment for reliability purposes; to evaluate the need for capital-intensive, long-lead-time resources; and to consider the need to accelerate the RPS compliance target. Apart from those exceptions, the Reference System Plan, GHG Planning Price, LSE Plans, and Preferred System Plan developed through the IRP process would serve primarily as information resources regarding the cost and resource mix needed to achieve the state's GHG reduction goals.

IRP Informs Resource-Specific Procurement Decisions

During this IRP cycle, each resource-specific proceeding is expected to continue setting its own procurement targets, policies, and funding levels in consideration of the information developed in the IRP proceeding. However, for certain proceedings, such as the IDER and RPS proceedings, there are clear opportunities for IRP to inform incremental resource procurement in the short term.

As explained in **Chapter 3**, staff plans to use the RESOLVE model to define the marginal GHG abatement cost (i.e. GHG Planning Price) of achieving 2030 electric sector GHG targets. This price may be used as a "GHG adder" for certain cost-effectiveness tests, as proposed by staff in the IDER proceeding (R.14-10-003).[44] A potential near-term application of the staff-proposed GHG adder in the IDER proceeding is to reflect 2030 GHG compliance costs in the cost-effectiveness analyses in the upcoming Energy Efficiency (EE) Potential and Goals Study in the Energy Efficiency proceeding (R.13-11-005) (see Box 6.1).[45] Using these values in the IDER proceeding may mitigate the risk that cost-effective DERs are not available in the future to help meet these GHG reduction goals. Therefore, while it is not feasible to use IRP 2017-18 analysis to establish the 2018+ EE goals directly, using the GHG Planning Price associated with the Reference System Plan may facilitate alignment of EE goal-setting with reasonably anticipated IRP outcomes.

Box 6.1: Relation of GHG Planning Price to the IDER Proceeding

On February 9, 2017, the Commission issued a Ruling[46] seeking stakeholder comments on a staff proposal to (among other things) use a "GHG adder" in certain cost-effectiveness tests as a way to estimate the value of the reduced carbon emissions that DERs provide. The GHG adder in that context is the equivalent of the GHG Planning Price described in this proposal The IDER proposal recommended basing the value of the GHG adder, for electric measures, on the marginal cost of abatement (i.e., the cost of achieving California's GHG reduction goals for the electric sector) identified by the IRP process. The GHG adder or GHG Planning Price would then be used in the EE Potential Study,[47] which will quantify how much EE is cost-effective and achievable in the coming years and inform the Commission's determination of future EE goals.

The IRP process is unlikely to develop the GHG Planning Price until after the EE Potential Study is complete. As such, Energy Division's IDER staff has proposed to adopt an interim GHG adder for cost-effectiveness tests based on preliminary IRP modeling results.[48] This interim approach may enable these costs to be reflected in the CPUC's EE potential and goals process due for adoption in late summer 2017, as well as in the CEC's 2017 IEPR demand forecast and SB 350 EE target setting. The interim GHG adder may be used until the Commission is able to adopt a GHG Planning Price for IRP 2017-18 cycle via a

[44] http://www.cpuc.ca.gov/General.aspx?id=10710.
[45] Refer to: http://www.cpuc.ca.gov/General.aspx?id=6442452619
[46] For more information, refer to the February 9, 2017 ALJ Ruling Taking Comment on a Staff Proposal Recommending a Societal Cost Test, available at: http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=173203676.
[47] Refer to: http://www.cpuc.ca.gov/General.aspx?id=6442452619
[48] For more information, refer to the April 3, 2017, ALJ Ruling Requesting Comment on an Interim Greenhouse Gas Adder, available at: docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M182/K363/182363230.PDF.

Decision on the Reference System Plan, after which the Commission can determine whether and how to incorporate the GHG Planning Price into DER cost-effectiveness analysis.

Similarly, this IRP cycle has the potential to inform decision making within the RPS proceeding (R.15-02-020). Staff has committed to explore the alignment of the annual RPS Procurement Plan process with IRP in order to ensure procurement planning in RPS is logically informed by IRP and in a manner that conforms to scheduling needs. Staff is also developing a workplan for evolution of the least-cost, best-fit (LCBF) bid evaluation framework used for RPS resources, potentially for use as the foundation for a common resource valuation methodology that can be applied across all resources. As mentioned previously, central to the success of IRP is the establishment of a clear link between planning and procurement, which may be accomplished with a common resource valuation methodology. Such a methodology could capture resource valuation as defined in IRP modeling and planning in a way that can be expressed for procurement activities and bid evaluation. It would also provide a framework that allows different resource types to be evaluated through the same lens, while also recognizing the different attributes and capabilities that exist across resource types.

A structured means for identifying other opportunities to align planning, procurement, funding, approval, consideration of disadvantaged communities, and other proceeding-specific activities with IRP cycles is articulated in **Chapter 7**.

IRP May Direct Individual Resource Procurement or Infrastructure Investment

In additional to informing decision making in resource-specific proceedings, the IRP 2017-18 cycle may also be used to direct procurement or investment for reliability purposes, evaluate the need for capital-intensive, long-lead-time resources, and consider whether to accelerate the RPS compliance target.

If long-term reliability needs that require new investment are clearly identified through IRP 2017-18, or unexpected short-term reliability needs arise, the IRP proceeding will contemplate directing procurement to satisfy those needs. This would include any investments that are clearly demonstrated to be needed to replace retiring resources. In the meantime, staff recommends that all existing CPUC requirements for filing bundled plans remain in effect (see Box 6.2). In future IRP cycles, bundled plan requirements may be changed to facilitate coordination with the IRP process.

Box 6.2. Alignment between IRP and Bundled Procurement Plans

Public Utilities Code Section 454.5 requires that the IOUs prepare procurement plans for review and approval by the CPUC and ensures that all costs associated with transactions executed by an IOU in accordance with its CPUC-approved procurement plan will be fully recoverable.

Traditionally, bundled procurement plans have been filed in every other LTPP proceeding. The most recent Rulemaking where bundled plans were considered was R.13-12-010, in which D.15-10-031 approved the IOUs' 2014 bundled procurement plans. Following the historical cycle, the next set of bundled plans would be filed in 2018.

As previous CPUC decisions have indicated, the review and approval of utility procurement plans as required under Public Utilities Code Section 454.5 is complex and evolving. Staff does not propose any changes to the bundled procurement plan process for the 2017-18 IRP cycle; however, Staff does intend to explore potential interactions between IRP and bundled procurement practices and policies as the IRP process moves forward. In the 2020-21 IRP cycle, bundled plan requirements may be changed to facilitate coordination with the IRP process.

This first round of IRP may also be used to evaluate the potential need for capital-intensive, long lead-time resources. While staff does not anticipate that an IRP Decision would direct procurement of such resources in IRP 2017-18, staff does propose that CPUC open a new track or proceeding to further explore any capital intensive, long-lead time resources that IRP analysis indicates is likely to be beneficial. This could be done via Commission Decision adopting the 2017 Reference System Plan. Staff's proposal for examining three types of such resources (OOS wind, bulk storage, and geothermal) is explained in detail in **Chapter 4.**

Finally, if the CPUC adopts a Reference System Plan that requires new investment in zero carbon energy, IRP will consider accelerating the date by which 50% RPS must be achieved. If the CPUC adopts a Reference System Plan that does not require new investment in zero-carbon energy, then staff would not anticipate accelerating the RPS compliance date.

The reason for potentially accelerating the RPS compliance date is that current REC bank volumes could impede the investments required to reduce GHG emissions to levels consistent with a "large share" or "extra-large share" case as described in **Chapter 4**. Raising the RPS to 50% before 2030 could reduce banked REC volumes and accelerate the new investment needed to displace fossil generation. In this way, staff's proposed approach to procurement would be backed by the RPS program rules in order to ensure compliance. Accelerating the RPS compliance date would only be undertaken after careful consideration of RPS rules and potential alternative mechanisms for ensuring GHG emission reductions. Parties are encouraged to respond to Question 30c in the ruling to ensure that CPUC considers all practical implications of and feasible alternatives to such an action.

Looking ahead to the next IRP cycle (2019-20), staff anticipates that LSE will file LSE Plans that document progress toward implementing the actions identified in their 2017 LSE Plans. If insufficient progress is demonstrated, the CPUC may be more likely to adopt a target-setting approach. For example, if the CPUC finds that insufficient new resources are being procured to reduce GHG emissions and meet other state goals, it may be more likely to raise the on its own authority. In this way, the existing compliance rules embedded within current resource-specific programs may be used as backstop to ensure that all LSEs comply with their own plans.

Box 6.3. How DACs should be considered during procurement

Although the Commission has stated in previous decisions[49] that IOUs should favor projects that do not result in siting a disproportionate number of carbon-intensive resources in low income and minority communities in their RFOs, the IRP process will ensure that the consideration of disadvantaged communities informs the Commission's planning activities through the IRP proceeding, or through the scoping of disadvantaged community issues into other proceedings.

The Commission currently requires LSEs to give preference to renewable projects that provide environmental and economic benefits to communities afflicted with poverty, high unemployment, or high emission levels of GHGs and air pollution. This requirement applies to the procurement of all renewable energy resources (PU Code Section 399.13(a)(7)). The Commission also requires LSEs to actively seek bids and give greater preferences for resources that are not gas-fired generating units in communities suffering from pollution burdens (PU Code Section 454.5(b)(9)(D)).

For IRP 2017, staff proposes that LSEs assess the impacts of individual projects on a DAC and quantify the costs and benefits associated with prioritizing non-fossil projects based on the metrics that result from the above-mentioned DAC analyses detailed in **Chapter 4**.

Cost Allocation and Recovery in IRP 2017-18

This section addresses expectations for cost allocation and recovery for new resources proposed to be procured by the IOUs.

One assumption staff states at the outset is that individual LSE Plans are expected to meet reliability, environmental, and cost requirements for its customers and independent of system-wide effects. In other words, staff expects that each LSE will be required to present a balanced portfolio that meets all portfolio objectives laid out in law and/or by the CPUC, including for individual resource requirements such as resource adequacy, RPS, storage, etc. (refer to **Chapter 5**). The individual Plans also should discuss the extent to which the plans adhere to the Reference System Plan portfolio resource balance, and to the extent they do not, explain why there are differences.

Once the individual LSE Plans are submitted to the CPUC, staff recommends that the Plans be evaluated to verify that each LSE's strategies and portfolios are balanced and reliable individually. Particular attention should be focused on whether there are sufficient resources for renewable integration. In addition, staff recommends that the CPUC consider the Plans collectively to determine whether the resources contemplated by all Plans are sufficient to ensure system reliability and meet GHG objectives (refer to **Chapter 5** for staff recommendations on the IRP review process).

[49] E.g., D.07-12-052

Should the CPUC determine that there is a need for additional resources beyond those planned by the individual LSEs, the CPUC may require an LSE to modify or supplement its plan. However, the CPUC's ability to order procurement of specific resources may necessarily be limited for certain types of LSEs.

Therefore, after taking all steps possible to ensure that individual LSEs take on the responsibility for the reliability and emissions aspects of their individual portfolios, if there is still a gap or need for additional resources identified, the CPUC's only recourse may be to require additional procurement by the three large IOUs. Should this occur, if the gap is a reliability concern, staff proposes that the costs of individual procurement be covered by all customers of the relevant IOU in accordance with existing policy. However, if there is a gap in resources needed to achieve other state policies, such as GHG reduction, the CPUC will need to determine how to allocate the costs of the additional necessary procurement.[50] Should this situation occur, the CPUC may reserve the right to allocate the procurement costs to all benefitting customers, including those of CCAs and ESPs.

So long as the CCAs and ESPs present Plans that meet reliability and GHG reduction requirements at the LSE level, as outlined by staff in **Chapter 5**, then staff would recommend that only IOU bundled ratepayers cover the costs of additional IOU procurement identified in the individual IOU Plans. That procurement would then be deemed needed for serving IOU bundled customers only (refer to the "Procurement Checkpoints" section at the beginning of this chapter).

[50] CAM is a regulatory process for allocating capacity costs of utility procurement across all benefitting customers. More information is available at: http://www.cpuc.ca.gov/General.aspx?id=6949

Chapter 7: Process Alignment Workplan

Successful implementation of the IRP process will require a high level of coordination, collaboration, and alignment between IRP and other resource programs and proceedings at the CPUC (i.e., "internal process alignment"), as well as coordination among the CPUC, CEC, CARB, and CAISO (i.e., "external process alignment").

- Internal process alignment: Many pre-existing statutory and administrative requirements are associated with resource areas that are affected by IRP (e.g., energy efficiency, storage, renewables, distributed generation, demand response). The relationship between specific resource procurement mandates, overseen in other proceedings that authorize procurement, and the inputs/outputs of the IRP portfolio optimization process, will need to be clearly defined.
- External process alignment: Many resource planning activities are interdependent with those of the CPUC's sister agencies and the CAISO, so clearly defining these relationships is critical to ensuring both the efficacy of the IRP process, as well as consistency with the planning outcomes at the other agencies and the CAISO.

The sections that follow describe at a high level CPUC staff's proposal for both internal and external process alignment, with a focus on what can be accomplished in the short term. It is important to note that the timing and scope of some external alignment relationships (e.g., IRP and IEPR) will depend on the nature of coordination between IRP and other CPUC resource proceedings (e.g., energy efficiency).

Staff Workplan and Goals for Internal Process Alignment

The IRP Rulemaking (R.16-02-007) listed 19 different procurement-related proceedings that could fall within the planning scope of IRP. The success of IRP is largely dependent on the alignment between IRP and those affected resource program proceedings.

Staff has constructed an internal workplan that allows for CPUC stakeholders—regulatory analysts, management, Administrative Law Judges (ALJs), and Commissioner Offices—to work together in a structured and transparent fashion towards process alignment. The workplan is divided into three work paths:

- **<u>Path 1: Identifying opportunities for process alignment</u>.** This path creates a structured means for identifying opportunities to align planning, procurement, funding, approval, consideration of disadvantaged communities, and other proceeding-specific activities with the integrated resource planning process. Examples of these activities could include provision of marginal GHG abatement cost curves to the IDER proceeding for use in resource valuation or the alignment of target setting and scheduling processes in the RPS proceeding with IRP cycles. These opportunities should reflect the market, regulatory, operational, and procedural coordination realities that would need to be addressed between now and the end of 2018 in order to ensure that IRP interacts with other resource proceedings in a logical, timely, and effective manner.

Once identified, these opportunities will be integrated into an IRP Master Calendar that can act as a roadmap for internal process alignment at the CPUC and a building block for the Engagement Plan for Process Alignment (Path 3 below).

- **Path 2: Establishing a formal internal process for vetting IRP inputs and outputs**. The IRP process will be cyclical in nature, with other proceedings informing IRP and vice versa. In the interest of establishing coherent and regular processes for coordination and sharing of information, IRP staff will work with staff from affected proceedings to make sure that IRP inputs and outputs appropriately reflect the market, regulatory, and operational issues associated with affected proceedings and resource programs. Examples include data assumptions that act as inputs to IRP or the Reference Plan outputs that will result from IRP modeling.
- **Path 3: Establishing formal, Commissioner-level engagement practices via "Engagement Plan for Process Alignment."** IRP staff intends to work with Commissioner offices to develop an Engagement Plan for Process Alignment that articulates a clear vision, goals, and timeline for process alignment at the CPUC. Roles for Commissioners, ALJs, and staff will be defined, as well as a description of the means by which process alignment is expected to occur (Decision, Resolution, Ruling, etc.) vis a vis the deliverables identified in Path 1 and Path 2. Conceivably, this Engagement Plan could be consulted when scoping and amending proceedings, and that the IRP Master Calendar will be used to inform development of a public "road map" of CPUC proceedings for stakeholders. IRP staff will coordinate closely with Commissioner offices to facilitate consensus on a plan that could eventually be adopted by the Commission itself. Likewise, LSEs will be asked to identify their own plans to identify process alignment opportunities and facilitate them inside their own organizations.

Staff recognizes that Commission proceedings are dynamic and can experience mid-course timeline changes. Moreover, the calendar for future IRP cycles is still under development. In order to accommodate these future uncertainties and maintain the flexibility necessary to align IRP with current and future Commission proceedings, the process alignment workplan will be an ongoing effort.

It is anticipated that IRP process alignment will help provide:

- A better understanding of how effectively the different resource programs facilitate the CPUC achieving the 2030 GHG emission reduction goals in a timely fashion and at the lowest cost.
- A coherent and consistent investment signal to the market and LSEs.
- A clear articulation of how analysis and decisions from a proceeding will impact another proceeding(s).
- A "roadmap" for CPUC proceedings so stakeholders can more effectively participate at the CPUC, especially given the stakeholders' limited resources and the increasing complexity of energy regulation. The IRP Master Calendar created as part of Path 1 will act as a foundation for this public roadmap, which will be adopted as part of the Engagement Plan for Process Alignment.

- A means to minimize the duplication of effort across proceedings and amongst staff; specifically, aim to consolidate filings or other procedural actions between IRP and another proceeding where the policy considerations are essentially the same. Guidance on the coordination of scoping and amending proceedings will be provided via the Engagement Plan for Process Alignment.
- A feedback loop whereby planning informs procurement, and vice versa. Development of a common resource valuation methodology, successful external process alignment with other agencies, and alignment of Path 1 and Path 2 deliverables should ensure creation of this feedback loop in time for the next IRP cycle in 2019-20.

Updates to External Process Alignment (IEPR–IRP–TPP)

In 2010, the CPUC and CAISO entered into an MOU to ensure alignment between their major infrastructure planning processes: the biennial LTPP and the annual Transmission Planning Process (TPP)[51]. In 2013, the CPUC, CEC, and the CAISO committed to a process to coordinate on preferred resource assumptions in the CEC's biennial Integrated Energy Policy Report (IEPR) and recommend a single forecast set for use in procurement and transmission planning processes.[52] In late 2013, the CPUC, CEC, and CAISO began implementation of a new alignment process between IEPR-LTPP-TPP, which was articulated in documentation produced by joint agency staff in December 2014.[53] In addition to clarifying expectations for use of information flowing from one entity to another for a specific study, an ongoing review process seeks to identify implementation issues and to overcome unforeseen challenges.

This alignment helped to ensure that the various resource planning studies were based on consistent and up-to-date inputs; established clear expectations among the stakeholders and the agencies regarding the timing of flows of information, study results, and other inputs between the processes; and maximized interagency collaboration in the development of key assumptions and study approaches, thereby meeting California's policy goals in a coordinated and effective manner.

In keeping with this inter-agency understanding, on February 28, 2017, the CPUC provided assumptions and a scenario to be used in the CAISO's TPP in the 2017 Assumptions and One Scenario Document (A&S Document). This A&S Document memorialized a standardized set of assumptions to be used as inputs

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[51] Memorandum of Understanding, available at: http://www.caiso.com/Documents/100517DecisiononRevisedTransmissionPlanningProcess-CPUCMOU.pdf

[52] See "Padilla Letter" Interagency Coordination on Demand Forecast Assumptions in Procurement and Transmission Planning at: http://www.cpuc.ca.gov/General.aspx?id=6617

[53] See "CPUC-CEC-CAISO LTPP/TPP Process Alignment" at http://www.cpuc.ca.gov/General.aspx?id=6617

into the CAISO's 2017-2018 TPP, and also provided a single scenario to inform the reliability-driven analysis that occurs as part of the TPP.

As the CPUC transitions from the LTPP framework to the IRP framework, alignment across joint agencies' respective planning processes may no longer function exactly in the way it was envisioned previously. This is due to two key differences between the LTPP and IRP frameworks. First, IRP cycles, though anticipated to be two years in duration like LTPP, will include different activities, such as the development of the Reference System Plan, review and evaluation of LSE plans, and finalization of the Preferred System Plan. These activities will require a significant amount of time to complete and therefore may require different alignment with the existing IEPR and TPP cycles. Second, CPUC staff intends for future IRP cycles to produce a higher degree of optimization for demand-side resources (those resources under CPUC influence) that can be used to inform the "managed demand forecast" in future IEPR cycles. This is a significant difference from LTPP, which was focused on identifying supply-side resources needed to ensure grid reliability in a cost-effective manner given a series of "expected" levels of resource development flowing out of separate CPUC proceedings. Therefore, CPUC staff plans to work with the CEC and CAISO in this IRP cycle to revise the 2014 staff document on infrastructure planning alignment,[54] to transition the interagency alignment from IEPR-LTPP-TPP alignment to IEPR-IRP-TPP alignment. Established interagency coordination mechanisms, including the Joint Agency Steering Committee, will facilitate discussion of these important alignment issues.

CPUC staff sees the primary desired outcome of external process alignment to be the use of agreed-upon assumptions across the IEPR-IRP-TPP planning processes. Therefore, the primary goals of external process alignment efforts in IRP 2017-18 (in combination with any follow-on CPUC decisions in resource proceedings) will be higher level of coordination between IRP and the 2019 IEPR, the 2018-19 TPP, and the 2019-20 TPP. A secondary goal of process alignment efforts will be to identify regional generation and transmission issues that could benefit from further study in the Western Energy Coordinating Council's (WECC) Transmission Expansion Planning Policy Committee (TEPPC), which is in the process of transitioning to a new Reliability Assurance Committee framework.

Alignment with CEC IEPR

Using agreed-upon assumptions in the CEC's IEPR forecast for California energy demand is crucial to consistent long-term planning. The IEPR process has not traditionally taken every demand-side input that flowed from the CPUC—such as energy efficiency, demand response, and behind-the-meter storage assumptions—from the LTPP process. It is anticipated that, in the future, the IRP process will provide incremental impacts from CPUC policies to IEPR. Thus, this part of the previous IEPR-LTPP-TPP alignment will likely require some adjustments. CPUC staff anticipates the first opportunity for IRP to align with the CEC's IEPR is for the 2019 IEPR cycle.

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[54] Refer to: http://cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6630

CPUC staff recognizes that the CEC is under a statutory mandate to forecast IEPR demand on a "reasonably expected to occur" standard. For load-modifying resource assumptions that flow from the CPUC, CEC practice has historically been to equate this "reasonably expected to occur" standard with the adoption of policies and funding for that particular resource type in a relevant CPUC proceeding. Continuing to work within this structure will be imperative as we move towards IEPR-IRP-TPP alignment. As such, CPUC staff is committed to defining where relevant target-setting exercises are vetted and adopted—whether in the IRP proceeding itself or the individual resource proceedings—in an expeditious manner. Delays that prevent load-modifying assumptions from flowing into the 2019 IEPR schedule could result in misalignment of California's planning processes, with the next opportunity in a full IEPR not occurring for another two years after adoption of the IRP Preferred System Plan (2021 IEPR). CPUC staff is also open to exploring with the CEC the opportunity to establish a process whereby these inputs could flow into the IEPR on an annual basis.

IRP alignment with the CEC IEPR process will take time and coordination. There are three additional reasons why IRP-IEPR alignment likely must wait until the 2019 IEPR cycle:

1) Scheduling constraints: Development, vetting, and adoption of an IRP Preferred System Plan containing LSE portfolios is necessary to meaningfully inform the IEPR process. The IRP 2017-18 will not adopt a Preferred System Plan likely until late 2018.

2) Vetting in individual CPUC proceedings: Changes to affected resource proceedings necessary for alignment with IRP may be need to be vetted and adopted in those individual proceedings prior the effects of those changes being incorporated into IEPR and thus the state's long-term planning activities.

3) Degree of CPUC influence: Delineating of which assumptions, and which parts of those assumptions, are influenced by CPUC policies, and to what extent, will require further study.

4) "Update" vs. "Full" IEPR: The 2018 IEPR is an "update" year, which typically involves the adoption of only limited updates to the previous "full" IEPR. Consideration of the broader results from the IRP's Preferred System Plan is likely out of scope for an IEPR "update" year.

Thus, 2019 represents the first iteration of the IEPR cycle that IRP could be expected to inform on a meaningful basis. CPUC staff will coordinate with CEC and CAISO in order to ensure timely and comprehensive alignment with the 2019 IEPR cycle.

Alignment with CAISO TPP

There are several steps necessary for full alignment between IRP and the CAISO TPP process. The preliminary steps involve provision of inputs by IRP for the 2018-19 TPP, along with a proposed "bridge" special study in the 2018-19 TPP. This carbon-constrained special study could provide a glide path towards full alignment with the TPP process, which could happen in the 2019-20 TPP after the adoption of the IRP Preferred System Plan in 2018. Regardless of timing, an important issue that merits further consideration is how to determine the specific points of interconnection used in TPP modeling for new resources identified in CPUC's IRP process. The initial effort using the RESOLVE model to address system flexibility and local capacity requirements may also need to be improved as policies making the electricity system more dependent upon demand-side and renewable resources become the focus of IRP.

- 2018-19 TPP: Traditionally, the CPUC's most current LTPP Assumptions and Scenarios document has acted as an input into the CAISO's TPP process. It is anticipated that the IRP Reference System Portfolio—and other portfolios documented in the Reference System Plan—could serve a similar role in informing the CAISO 2018-19 TPP process. The Reference System Portfolio will serve the same function as the RPS portfolios produced by Energy Division using the RPS Calculator in prior LTPP proceedings, to define the resources used by CAISO to identify policy-driven transmission infrastructure needs. The Reference System Portfolio will differ from RPS portfolios provided in the past in that it will reflect resources needed not just for the RPS, but also for GHG reduction and other policies. It would also potentially include resource types, such as storage, that were not part of RPS portfolios. Furthermore, other portfolios documented in the Reference System Plan, together with the assumptions used to create it, would provide full "scenarios" of optimized demand- and supply-side assumptions. Historically, the Energy Division has provided those assumptions—not optimized—in the A&S document and the Scenario Tool. These scenarios would be used in a similar manner to the scenarios produced in prior LTPP proceedings.
    - Special Study: CPUC staff proposes that CAISO use either the Reference System Plan (if it is not used for the purpose of identifying policy-driven transmission needs) or one or more of the alternative portfolios produced during Reference System Plan development for a special study in its 2018-19 TPP cycle. A portfolio reflecting a new and plausible future policy direction would be an appropriate candidate. For example, a portfolio reflecting a more stringent electric sector GHG emissions target could inform future thinking about the consequences of planning for increased low-carbon resource penetration levels and the necessary steps for successful integration of these resources prior to formal adoption of a Preferred System Plan in 2018 for use in the 2019-20 TPP cycle.
- 2019-20 TPP: Formal adoption of the IRP Preferred System Plan is anticipated to occur in late 2018, which would allow it to act as an input to the 2019-20 TPP process beginning in 2019. The Preferred System Plan will represent the combined plans of LSEs and can serve as the foundation for California's long-term planning, acting as a roadmap for the electricity sector to meet the state's 2030 GHG goals inside the constraints articulated by SB 350. In much the same way the RPS portfolios were used in TPP to identify transmission needed to support RPS policy, the new portfolios produced in IRP could be used to identify transmission needed to support the state's low-carbon policies.

Alignment with Regional Planning

CPUC staff also recognizes the value of regional planning and coordination regarding FERC Order 1000, a rule that reforms FERC's electric transmission planning and cost allocation requirements for public utility transmission providers.[55] Thus, CPUC staff proposes to work with CAISO in refining the draft Reference System Plan (in 2017) to capture generation and transmission issues that could benefit from further study. Issues identified as having potential value for further study can then be passed onto WECC for consideration by the new Reliability Assessment Committee (RAC), the successor to the Transmission Expansion Planning Policy Committee (TEPPC). It is anticipated that these issues would need to be submitted to WECC by early 2018 in order to be considered in the next RAC cycle and have actionable results back in time for potential adoption with the Preferred System Plan in late 2018.

CPUC staff also acknowledges the changing relationship between the geographic area covered by the IRP process and other balancing authority areas in California. As POUs respond to SB 350 GHG emission reduction goals, other changes in operation and planning within the State should not be overlooked. CPUC staff plans to coordinate with other affected agencies to ensure that this changing landscape is taken into account in 2017-18 IRP and beyond.

Next Steps

External process alignment will be an ongoing topic of discussion among CPUC, CEC, CAISO and CARB. Some changes may be resolved and can be ratified in a CPUC decision announcing a Reference System Plan. Others may require more time, or simply need the benefit of operating the CEC and CPUC IRP processes for one complete cycle to fully understand and resolve.

[55] Refer to: https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp.

Appendix A: SB 350 Sections 454.51 and 454.52

Section 454.51

The commission shall do all of the following:

(a) Identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner. The portfolio shall rely upon zero carbon-emitting resources to the maximum extent reasonable and be designed to achieve any statewide greenhouse gas emissions limit established pursuant to the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code) or any successor legislation.

(b) Direct each electrical corporation to include, as part of its proposed procurement plan, a strategy for procuring best-fit and least-cost resources to satisfy the portfolio needs identified by the commission pursuant to subdivision (a).

(c) Ensure that the net costs of any incremental renewable energy integration resources procured by an electrical corporation to satisfy the need identified in subdivision (a) are allocated on a fully nonbypassable basis consistent with the treatment of costs identified in paragraph (2) of subdivision (c) of Section 365.1.

(d) Permit community choice aggregators to submit proposals for satisfying their portion of the renewable integration need identified in subdivision (a). If the commission finds this need is best met through long-term procurement commitments for resources, community choice aggregators shall also be required to make long-term commitments for resources. The commission shall approve proposals pursuant to this subdivision if it finds all of the following:

   (1) The resources proposed by a community choice aggregator will provide equivalent integration of renewable energy.

   (2) The resources proposed by a community choice aggregator will promote the efficient achievement of state energy policy objectives, including reductions in greenhouse gas emissions.

   (3) Bundled customers of an electrical corporation will be indifferent from the approval of the community choice aggregator proposals.

   (4) All costs resulting from nonperformance will be borne by the electrical corporation or community choice aggregator responsible for them.

Section 454.52

(a)

(1) Commencing in 2017, and to be updated regularly thereafter, the commission shall adopt a process for each load-serving entity, as defined in Section 380, to file an integrated resource plan, and a schedule for periodic updates to the plan, to ensure that load-serving entities do the following:

(A) Meet the greenhouse gas emissions reduction targets established by the State Air Resources Board, in coordination with the commission and the Energy Commission, for the electricity sector and each load-serving entity that reflect the electricity sector's percentage in achieving the economy-wide greenhouse gas emissions reductions of 40 percent from 1990 levels by 2030.

(B) Procure at least 50 percent eligible renewable energy resources by December 31, 2030, consistent with Article 16 (commencing with Section 399.11) of Chapter 2.3.

(C) Enable each electrical corporation to fulfill its obligation to serve its customers at just and reasonable rates.

(D) Minimize impacts on ratepayers' bills.

(E) Ensure system and local reliability.

(F) Strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities.

(G) Enhance distribution systems and demand-side energy management.

(H) Minimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code.

(2)

(A) The commission may authorize all source procurement for electrical corporations that includes various resource types including demand-side resources, supply side resources, and resources that may be either demand-side resources or supply side resources, taking into account the differing electrical corporations' geographic service areas, to ensure that each load-serving entity meets the goals set forth in paragraph (1).

(B) The commission may approve procurement of resource types that will reduce overall greenhouse gas emissions from the electricity sector and meet the other goals specified in paragraph (1), but due to the nature of the technology or fuel source may not compete favorably in price against other resources over the time period of the integrated resource plan.

(b)

(1) Each load-serving entity shall prepare and file an integrated resource plan consistent with paragraph (2) of subdivision (a) on a time schedule directed by the commission and subject to commission review.

(2) Each electrical corporation's plan shall follow the provisions of Section 454.5.

(3) The plan of a community choice aggregator shall be submitted to its governing board for approval and provided to the commission for certification, consistent with paragraph (5) of subdivision (a) of Section 366.2, and shall achieve the following:

(A) Economic, reliability, environmental, security, and other benefits and performance characteristics that are consistent with the goals set forth in paragraph (1) of subdivision (a).

(B) A diversified procurement portfolio consisting of both short-term and long-term electricity and electricity-related and demand reduction products.

(C) The resource adequacy requirements established pursuant to Section 380.

(4) The plan of an electric service provider shall achieve the goals set forth in paragraph (1) of subdivision (a) through a diversified portfolio consisting of both short-term and long-term electricity, electricity-related, and demand reduction products.

(c) To the extent that additional procurement is authorized for the electrical corporation in the integrated resource plan or the procurement process authorized pursuant to Section 454.5, the commission shall ensure that the costs are allocated in a fair and equitable manner to all customers consistent with 454.51, that there is no cost-shifting among customers of load-serving entities, and that community choice aggregators may self-provide renewable integration resources consistent with Section 454.51.

(d) In order to eliminate redundancy and increase efficiency, the process adopted pursuant to subdivision (a) shall incorporate, and not duplicate, any other planning processes of the commission.

Appendix B: List of Values for Each IRP Modeling Assumption

This appendix includes tables showing the major assumptions in each sensitivity and future.

For more information about how each assumption is defined and how it was developed, see the DRAFT RESOLVE Inputs and Assumptions document available on the CPUC's website at: http://www.cpuc.ca.gov/irp_proposal/. The Inputs and Assumptions document is also reproduced within this appendix following the tables.

For the detailed numerical values underlying each assumption, see the RESOLVE Scenario Tool workbook, available on the CPUC's website at: http://www.cpuc.ca.gov/irp_proposal/.

Key Assumptions for RESOLVE Cases

Name in RESOLVE Scenario Tool:	Default	Medium	Large	VeryLarge
Name in Staff Proposal:	Default	Medium	Large	Very large
Load				
Electric Vehicle Adoption	CARB Scoping Plan - SP	CARB Scoping Plan - SP	CARB Scoping Plan - SP	CARB Scoping Plan - SP
Building Electrification	CEC 2016 IEPR - Mid Demand	CEC 2016 IEPR - Mid Demand	CEC 2016 IEPR - Mid Demand	CEC 2016 IEPR - Mid Demand
Behind-the-meter PV	CEC 2016 IEPR - Mid PV	CEC 2016 IEPR - Mid PV	CEC 2016 IEPR - Mid PV	CEC 2016 IEPR - Mid PV
Energy Efficiency	CEC 2016 IEPR - Mid AAEE + AB802	CEC 2016 IEPR - Mid AAEE + AB802	CEC 2016 IEPR - Mid AAEE + AB802	CEC 2016 IEPR - Mid AAEE + AB802
Existing DR	Mid	Mid	Mid	Mid
TOU Adjustment	High (MRW S4 x1.5)	High (MRW S4 x1.5)	High (MRW S4 x1.5)	High (MRW S4 x1.5)
Workplace Charger Availability	Mid	Mid	Mid	Mid
EV Charging Flexibility	Low	Low	Low	Low
Allow Flexible Loads?	0	0	0	0
Renewables				
2030 RPS	no RPS	no RPS	no RPS	no RPS
GHG Target	Default	Medium	Large	Very Large
Environmental Screen for Resource Potential	DRECP + SJV	DRECP + SJV	DRECP + SJV	DRECP + SJV
Allow Banking?	0	0	0	0
Out-Of-State Renewable Filter	Existing Tx Only	Existing Tx Only	Existing Tx Only	Existing Tx Only
Costs				
Fuel Prices	Mid	Mid	Mid	Mid
Carbon Prices	Low	Low	Low	Low
Solar	Mid	Mid	Mid	Mid
Lithium Ion Batteries	Mid	Mid	Mid	Mid
Flow Batteries	Mid	Mid	Mid	Mid
Enable ITC/PTC (if not enabled, will expire early)	1	1	1	1
Discount Rate	5%	5%	5%	5%
Financing Years Post Final Year	20	20	20	20
Operations				
Simultaneous Flow Limits	Mid	Mid	Mid	Mid
2030 Load Following Reserves	50% High Solar	50% High Solar	50% High Solar	50% High Solar
Max. Fraction of Load Following Down met by Renewables	50%	50%	50%	50%
Other Sensitivities				
Local Capacity Needs	Low	Low	Low	Low
Coal Flexibility	Dispatchable	Dispatchable	Dispatchable	Dispatchable
Storage Mandate Case	None	None	None	None
Allow Pumped Storage Build	1	1	1	1
Allow Battery Storage Build	1	1	1	1
Retirement Date Diablo Unit 1	12/31/2024	12/31/2024	12/31/2024	12/31/2024
Retirement Date Diablo Unit 2	12/31/2025	12/31/2025	12/31/2025	12/31/2025
Gas Retirement (excl. CHP)	No early retirement	No early retirement	No early retirement	No early retirement
CHP Retirement	No early retirement	No early retirement	No early retirement	No early retirement
Specified Resources				
Resource 1				
Resource ID				
Quantity (MW)				
Year				
Resource 2				
Resource ID				
Quantity (MW)				
Year				
Resource 3				
Resource ID				
Quantity (MW)				
Year				

Key Assumptions for RESOLVE Cases

Name in RESOLVE Scenario Tool:	Default_EE-High	Default_EE-Low	Default_BTM_PV-High	Default_BTM_PV-Low	Default_ZEV_Flex	Default_Bldg_Elect-High
Name in Staff Proposal:	EE-High	EE-Low	BTM PV-High	BTM PV-Low	ZEV Flex	Bldg Elect-High
Load						
Electric Vehicle Adoption	CARB Scoping Plan - SP	CARB Scoping Plan - SP	CARB Scoping Plan - SP	CARB Scoping Plan - SP	CARB Scoping Plan - SP	CARB Scoping Plan - SP
Building Electrification	CEC 2016 IEPR - Mid Demand	CEC 2016 IEPR - Mid Demand	CEC 2016 IEPR - Mid Demand	CEC 2016 IEPR - Mid Demand	CEC 2016 IEPR - Mid Demand	CARB Scoping Plan - Alt1
Behind-the-meter PV	CEC 2016 IEPR - Mid PV	CEC 2016 IEPR - Mid PV	CEC 2016 IEPR - High PV	CEC 2016 IEPR - Low PV	CEC 2016 IEPR - Mid PV	CEC 2016 IEPR - Mid PV
Energy Efficiency	CEC 2016 IEPR - Mid AAEE (x2)	CEC 2016 IEPR - Mid AAEE	CEC 2016 IEPR - Mid AAEE + AB802	CEC 2016 IEPR - Mid AAEE + AB802	CEC 2016 IEPR - Mid AAEE + AB802	CEC 2016 IEPR - Mid AAEE + AB802
Existing DR	Mid	Mid	Mid	Mid	Mid	Mid
TOU Adjustment	High (MRW S4 x1.5)	High (MRW S4 x1.5)	High (MRW S4 x1.5)	High (MRW S4 x1.5)	High (MRW S4 x1.5)	High (MRW S4 x1.5)
Workplace Charger Availability	Mid	Mid	Mid	Mid	High	Mid
EV Charging Flexibility	Low	Low	Low	Low	High	Low
Allow Flexible Loads?	0	0	0	0	0	0
Renewables						
2030 RPS	no RPS	no RPS	no RPS	no RPS	no RPS	no RPS
GHG Target	Default	Default	Default	Default	[will run for all 4 targets]	[will run for all 4 targets]
Environmental Screen for Resource Potential	DRECP + SJV	DRECP + SJV	DRECP + SJV	DRECP + SJV	DRECP + SJV	DRECP + SJV
Allow Banking?	0	0	0	0	0	0
Out-Of-State Renewable Filter	Existing Tx Only	Existing Tx Only	Existing Tx Only	Existing Tx Only	Existing Tx Only	Existing Tx Only
Costs						
Fuel Prices	Mid	Mid	Mid	Mid	Mid	Mid
Carbon Prices	Low	Low	Low	Low	Low	Low
Solar	Mid	Mid	Mid	Mid	Mid	Mid
Lithium Ion Batteries	Mid	Mid	Mid	Mid	Mid	Mid
Flow Batteries	Mid	Mid	Mid	Mid	Mid	Mid
Enable ITC/PTC (if not enabled, will expire early)	1	1	1	1	1	1
Discount Rate	5%	5%	5%	5%	5%	5%
Financing Years Post Final Year	20	20	20	20	20	20
Operations						
Simultaneous Flow Limits	Mid	Mid	Mid	Mid	Mid	Mid
2030 Load Following Reserves	50% High Solar	50% High Solar	50% High Solar	50% High Solar	50% High Solar	50% High Solar
Max. Fraction of Load Following Down met by Renewables	50%	50%	50%	50%	50%	50%
Other Sensitivities						
Local Capacity Needs	Low	Low	Low	Low	Low	Low
Coal Flexibility	Dispatchable	Dispatchable	Dispatchable	Dispatchable	Dispatchable	Dispatchable
Storage Mandate Case	None	None	None	None	None	None
Allow Pumped Storage Build	1	1	1	1	1	1
Allow Battery Storage Build	1	1	1	1	1	1
Retirement Date Diablo Unit 1	12/31/2024	12/31/2024	12/31/2024	12/31/2024	12/31/2024	12/31/2024
Retirement Date Diablo Unit 2	12/31/2025	12/31/2025	12/31/2025	12/31/2025	12/31/2025	12/31/2025
Gas Retirement (excl. CHP)	No early retirement	No early retirement	No early retirement	No early retirement	No early retirement	No early retirement
CHP Retirement	No early retirement	No early retirement	No early retirement	No early retirement	No early retirement	No early retirement
Specified Resources						
Resource 1						
Resource ID						
Quantity (MW)						
Year						
Resource 2						
Resource ID						
Quantity (MW)						
Year						
Resource 3						
Resource ID						
Quantity (MW)						
Year						

Key Assumptions for RESOLVE Cases

Name in RESOLVE Scenario Tool:	Default_PV_Cost_High	Default_ST_Cost_High	Default_PV_Cost_Low	Default_ST_Cost_Low	Default_Early_Retirement	Default_CHP_Retirement
Name in Staff Proposal:	PV Cost High	ST Cost High	PV Cost Low	ST Cost Low	Early Retirement	CHP Retirement
Load						
Electric Vehicle Adoption	CARB Scoping Plan - SP	CARB Scoping Plan - SP	CARB Scoping Plan - SP	CARB Scoping Plan - SP	CARB Scoping Plan - SP	CARB Scoping Plan - SP
Building Electrification	CEC 2016 IEPR - Mid Demand	CEC 2016 IEPR - Mid Demand	CEC 2016 IEPR - Mid Demand	CEC 2016 IEPR - Mid Demand	CEC 2016 IEPR - Mid Demand	CEC 2016 IEPR - Mid Demand
Behind-the-meter PV	CEC 2016 IEPR - Mid PV	CEC 2016 IEPR - Mid PV	CEC 2016 IEPR - Mid PV	CEC 2016 IEPR - Mid PV	CEC 2016 IEPR - Mid PV	CEC 2016 IEPR - Mid PV
Energy Efficiency	CEC 2016 IEPR - Mid AAEE + AB802	CEC 2016 IEPR - Mid AAEE + AB802	CEC 2016 IEPR - Mid AAEE + AB802	CEC 2016 IEPR - Mid AAEE + AB802	CEC 2016 IEPR - Mid AAEE + AB802	CEC 2016 IEPR - Mid AAEE + AB802
Existing DR	Mid	Mid	Mid	Mid	Mid	Mid
TOU Adjustment	High (MRW S4 x1.5)	High (MRW S4 x1.5)	High (MRW S4 x1.5)	High (MRW S4 x1.5)	High (MRW S4 x1.5)	High (MRW S4 x1.5)
Workplace Charger Availability	Mid	Mid	Mid	Mid	Mid	Mid
EV Charging Flexibility	Low	Low	Low	Low	Low	Low
Allow Flexible Loads?	0	0	0	0	0	0
Renewables						
2030 RPS	no RPS	no RPS	no RPS	no RPS	no RPS	no RPS
GHG Target	[will run for all 4 targets]	[will run for all 4 targets]	[will run for all 4 targets]	[will run for all 4 targets]	[will run for all 4 targets]	[will run for all 4 targets]
Environmental Screen for Resource Potential	DRECP + SJV	DRECP + SJV	DRECP + SJV	DRECP + SJV	DRECP + SJV	DRECP + SJV
Allow Banking?	0	0	0	0	0	0
Out-Of-State Renewable Filter	Existing Tx Only	Existing Tx Only	Existing Tx Only	Existing Tx Only	Existing Tx Only	Existing Tx Only
Costs						
Fuel Prices	Mid	Mid	Mid	Mid	Mid	Mid
Carbon Prices	Low	Low	Low	Low	Low	Low
Solar	High	Mid	Low	Mid	Mid	Mid
Lithium Ion Batteries	Mid	High	Mid	Low	Mid	Mid
Flow Batteries	Mid	High	Mid	Low	Mid	Mid
Enable ITC/PTC (if not enabled, will expire early)	1	1	1	1	1	1
Discount Rate	5%	5%	5%	5%	5%	5%
Financing Years Post Final Year	20	20	20	20	20	20
Operations						
Simultaneous Flow Limits	Mid	Mid	Mid	Low	High	High
2030 Load Following Reserves	50% High Solar	50% High Solar	50% High Solar	50% High Solar	50% High Solar	50% High Solar
Max. Fraction of Load Following Down met by Renewables	50%	50%	50%	50%	50%	50%
Other Sensitivities						
Local Capacity Needs	Low	Low	Low	Low	Low	Low
Coal Flexibility	Dispatchable	Dispatchable	Dispatchable	Dispatchable	Dispatchable	Dispatchable
Storage Mandate Case	None	None	None	None	None	None
Allow Pumped Storage Build	1	1	1	1	1	1
Allow Battery Storage Build	1	1	1	1	1	1
Retirement Date Diablo Unit 1	12/31/2024	12/31/2024	12/31/2024	12/31/2024	12/31/2024	12/31/2024
Retirement Date Diablo Unit 2	12/31/2025	12/31/2025	12/31/2025	12/31/2025	12/31/2025	12/31/2025
Gas Retirement (excl. CHP)	No early retirement	No early retirement	No early retirement	No early retirement	Retirement after 25 years	No early retirement
CHP Retirement	No early retirement	No early retirement	No early retirement	No early retirement	No early retirement	Retirement after 25 years
Specified Resources						
Resource 1						
Resource ID						
Quantity (MW)						
Year						
Resource 2						
Resource ID						
Quantity (MW)						
Year						
Resource 3						
Resource ID						
Quantity (MW)						
Year						

Key Assumptions for RESOLVE Cases

Name in RESOLVE Scenario Tool:	Default_High_DER	Default_High_Load	Default_Flex_Challenged
Name in Staff Proposal:	High DER	High Load	Flex Challenged
Load			
Electric Vehicle Adoption	CARB Scoping Plan - Alt1	CARB Scoping Plan - Alt1	CARB Scoping Plan - Alt1
Building Electrification	CARB Scoping Plan - Alt1	CARB Scoping Plan - Alt1	CARB Scoping Plan - Alt1
Behind-the-meter PV	CEC 2016 IEPR - High PV	CEC 2016 IEPR - Low PV	CEC 2016 IEPR - High PV
Energy Efficiency	CEC 2016 IEPR - Mid AAEE (x2)	CEC 2016 IEPR - Mid AAEE	CEC 2016 IEPR - Mid AAEE + AB802
Existing DR	Mid	Mid	Mid
TOU Adjustment	High (MRW S4 x1.5)	High (MRW S4 x1.5)	High (MRW S4 x1.5)
Workplace Charger Availability	Mid	Mid	Mid
EV Charging Flexibility	Low	Low	Low
Allow Flexible Loads?	0	0	0
Renewables			
2030 RPS	no RPS	no RPS	no RPS
GHG Target	[will run for all 4 targets]	[will run for all 4 targets]	[will run for all 4 targets]
Environmental Screen for Resource Potential	DRECP + SJV	DRECP + SJV	DRECP + SJV
Allow Banking?	0	0	0
Out-Of-State Renewable Filter	Existing Tx Only	Existing Tx Only	Existing Tx Only
Costs			
Fuel Prices	Mid	Mid	Mid
Carbon Prices	Low	Low	Low
Solar	Mid	Mid	Low
Lithium Ion Batteries	Mid	Mid	High
Flow Batteries	Mid	Mid	High
Enable ITC/PTC (if not enabled, will expire early)	1	1	1
Discount Rate	5%	5%	5%
Financing Years Post Final Year	20	20	20
Operations			
Simultaneous Flow Limits	Mid	Mid	Mid
2030 Load Following Reserves	50% High Solar	50% High Solar	50% High Solar
Max. Fraction of Load Following Down met by Renewables	50%	50%	50%
Other Sensitivities			
Local Capacity Needs	Low	Low	Low
Coal Flexibility	Dispatchable	Dispatchable	Dispatchable
Storage Mandate Case	None	None	None
Allow Pumped Storage Build	1	1	1
Allow Battery Storage Build	1	1	1
Retirement Date Diablo Unit 1	12/31/2024	12/31/2024	12/31/2024
Retirement Date Diablo Unit 2	12/31/2025	12/31/2025	12/31/2025
Gas Retirement (excl. CHP)	No early retirement	No early retirement	Retirement after 25 years
CHP Retirement	No early retirement	No early retirement	No early retirement
Specified Resources			
Resource 1			
Resource ID			
Quantity (MW)			
Year			
Resource 2			
Resource ID			
Quantity (MW)			
Year			
Resource 3			
Resource ID			
Quantity (MW)			
Year			

Key Assumptions for RESOLVE Cases

Name in RESOLVE Scenario Tool:	Default_OOS_Wind	Default_Long_Dur_Storage	Default_Geothermal
Name in Staff Proposal:	OOS Wind	Long Dur Storage	Geothermal
Load			
Electric Vehicle Adoption	CARB Scoping Plan - SP	CARB Scoping Plan - SP	CARB Scoping Plan - SP
Building Electrification	CEC 2016 IEPR - Mid Demand	CEC 2016 IEPR - Mid Demand	CEC 2016 IEPR - Mid Demand
Behind-the-meter PV	CEC 2016 IEPR - Mid PV	CEC 2016 IEPR - Mid PV	CEC 2016 IEPR - Mid PV
Energy Efficiency	CEC 2016 IEPR - Mid AAEE + AB802	CEC 2016 IEPR - Mid AAEE + AB802	CEC 2016 IEPR - Mid AAEE + AB802
Existing DR	Mid	Mid	Mid
TOU Adjustment	High (MRW S4 x1.5)	High (MRW S4 x1.5)	High (MRW S4 x1.5)
Workplace Charger Availability	Mid	Mid	Mid
EV Charging Flexibility	Low	Low	Low
Allow Flexible Loads?	0	0	0
Renewables			
2030 RPS	no RPS	no RPS	no RPS
GHG Target	[will run for all 4 targets]	[will run for all 4 targets]	[will run for all 4 targets]
Environmental Screen for Resource Potential	DRECP + SJV	DRECP + SJV	DRECP + SJV
Allow Banking?	0	0	0
Out-Of-State Renewable Filter	Existing Tx Only	Existing Tx Only	Existing Tx Only
Costs			
Fuel Prices	Mid	Mid	Mid
Carbon Prices	Low	Low	Low
Solar	Mid	Mid	Mid
Lithium Ion Batteries	Mid	Mid	Mid
Flow Batteries	Mid	Mid	Mid
Enable ITC/PTC (if not enabled, will expire early)	1	1	1
Discount Rate	5%	5%	5%
Financing Years Post Final Year	20	20	20
Operations			
Simultaneous Flow Limits	Mid	Mid	Mid
2030 Load Following Reserves	50% High Solar	50% High Solar	50% High Solar
Max. Fraction of Load Following Down met by Renewables	50%	50%	50%
Other Sensitivities			
Local Capacity Needs	Low	Low	Low
Coal Flexibility	Dispatchable	Dispatchable	Dispatchable
Storage Mandate Case	None	None	None
Allow Pumped Storage Build	1	1	1
Allow Battery Storage Build	1	1	1
Retirement Date Diablo Unit 1	12/31/2024	12/31/2024	12/31/2024
Retirement Date Diablo Unit 2	12/31/2025	12/31/2025	12/31/2025
Gas Retirement (excl. CHP)	No early retirement	No early retirement	No early retirement
CHP Retirement	No early retirement	No early retirement	No early retirement
Specified Resources			
Resource 1			
Resource ID	New_Mexico_Wind	CAISO_New_Pumped_Storage	Greater_Imperial_Geothermal
Quantity (MW)	1,500	1,000	1,000
Year	2026	2022	2022
Resource 2			
Resource ID	Wyoming_Wind		
Quantity (MW)	1,500		
Year	2026		
Resource 3			
Resource ID			
Quantity (MW)			
Year			

RESOLVE Documentation: CPUC 2017 IRP

Inputs & Assumptions (DRAFT)

May 2017

Energy+Environmental Economics

RESOLVE Model Documentation

Inputs & Assumptions (DRAFT)

May 2017

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Table of Contents

1 Introduction

1.1 Overview

RESOLVE is an optimal investment and operational model designed to inform long-term planning questions around renewables integration in systems with high penetration levels of renewable energy. The model is formulated as a linear optimization problem. RESOLVE co-optimizes investment and dispatch for a selected set of days over a multi-year horizon in order to identify least-cost portfolios for meeting renewable energy targets and other system goals. RESOLVE also incorporates a representation of neighboring regions in order to characterize transmission flows into and out of a main zone of interest endogenously. RESOLVE can solve for the optimal investments in renewable resources, various energy storage technologies, new gas plants, and gas plant retrofits subject to an annual constraint on delivered renewable energy that reflects the RPS policy, an annual constraint on greenhouse gas emissions, a capacity adequacy constraint to maintain reliability, constraints on operations that are based on a linearized version of the unit commitment problem, as well as constraints on the ability to develop specific renewable resources.

For the purposes of the CPUC's Integrated Resource Plan, E3 has developed inputs and assumptions for RESOLVE to create optimal portfolios for the CAISO electric system under a range of different forecasts of load growth, technology costs, fuel costs, and policy constraints. RESOLVE optimizes the buildout of new resources twenty years into the future, representing the fixed costs of new investments and the costs of operating the CAISO system within the broader footprint of the WECC electricity system.

This document summarizes key inputs and assumptions to the RESOLVE model under development for the California Public Utility Commission's (CPUC) 2017 Integrated Resource Plan (IRP). It is intended to accompany the Excel-based RESOLVE User Interface to provide parties with documentation of the inputs and assumptions contained within that spreadsheet.

1.2 Contents of User Interface

The Excel-based RESOLVE User Interface contains the complete set of inputs and assumptions needed to run a RESOLVE scenario spread across many worksheets. The tabs in the User Interface are grouped into several categories:

+ **System inputs (SYS):** inputs that broadly define the electric system;
+ **Load inputs (LOADS):** assumptions related to current and future loads;
+ **Renewable inputs (REN):** assumptions related to both existing and potential future renewable resources;
+ **Conventional generator inputs (CONV):** assumptions related to both existing and potential future gas, coal, and nuclear generators;
+ **Hydro generation inputs (HYD):** assumptions on the hydroelectric fleet;
+ **Storage-related inputs (STOR):** assumptions defining existing and future storage resource potential;
+ **DR-related inputs (DR):** assumptions defining existing and future demand response resource potential; and
+ **Resource costing module (COSTS):** a module used to calculate levelized costs of future generation resources based on assumed capital, O&M, and fuel costs.

The classification of each tab among these categories is indicated by its prefix. Subsequent sections of this document discuss the sourcing and development of information contained on these tabs; for completeness, a comprehensive inventory of the contents of the User Interface is presented in Table 1.

Table 1. RESOLVE User Interface table of contents

Input File	Description
SYS_Fuel_Costs	This worksheet provides all input data and calculations on fuel costs, including the carbon cost.
SYS_Planning_Reserve	This worksheet provides all input data and calculations regarding planning reserve margin and resource adequacy.
SYS_Local_Needs	This worksheet provides all input data and calculations regarding local capacity needs.
SYS_RPS_GHG_Targets	This worksheet includes all input data and calculations regarding the RPS and GHG targets in the CAISO system.
SYS_Regional_Settings	This worksheet contains all data and calculations regarding zonal transmission constraints, hurdle rates between zones, carbon adders for transmission into California, and simultaneous flow constraints (such as NW to California).
SYS_Reserves	This worksheet contains all data and calculations regarding reserve requirements (upward and downward), and the sub-hourly deployment of load-following down (which dictates how much sub-hourly curtailment occurs when renewables provide load-following down).
SYS_Reserves	This worksheet includes all the "Baseline" costs used to contextualize the resulting costs from RESOLVE. These costs are not direct inputs to the RESOLVE optimization, but are shown to place the total cost output of RESOLVE in the context of total electric sector costs.
LOADS_Forecast	This worksheet contains all data and calculations regarding the load forecast, such as the baseline consumption, EV forecast, behind-the-meter PV forecast, energy efficiency forecast etc. The data is both provided in terms of annual load (GWh) and contribution to peak load (MW).
LOADS_EV_Char	This worksheet contains all data and calculations regarding the operating characteristics of the EV fleet, such as workplace charging availability, EV charging flexibility, EV charging demand shapes, etc. When none of the EV charging is flexible, the EV shape is defined by the shape provided in the LOADS_Profiles worksheet. The EV driving demand shape is only used for the fraction of EV charging that is flexible, and coincides with the driving times (i.e. it peaks in the morning and evening). Note that the actual EV demand forecast is provided through the LOADS_Forecast worksheet.
LOADS_Profiles	This worksheet contains all data and calculations regarding the load shapes. For all non-CAISO zones, this is simply a normalized load shape for that entire zone. For the CAISO zone, the load shape is built up by combing a baseline consumption shape (no behind-the-meter PV, electric vehicles, energy efficiency, or time-of-use adjustments), an electric vehicle shape, an energy efficiency shape, and a time-of-use load modifier shape.
REN_Baseline	This worksheet contains all data and calculations regarding planned renewable resources for each of the modeled zones

Input File	Description
	(CAISO, NW, SW, LDWP, BANC, IID). For each zone and for each type of resource, the planned GWh of generation by year is drawn from the REN_Existing_Resources worksheet, which contains a list of all the planned renewable resources. Since RESOLVE works with MW of installed capacity rather than GWh of annual generation, the annual generation for each resource is converted to a MW number, using the RESOLVE capacity factor assumed for that resource. If the RESOLVE capacity factor dose not match the actual capacity factor, this will result in a different installed capacity number (MW). This is acceptable since the model will still match the annual generation, but it could confuse some users.
REN_Candidate	This worksheet contains all data and calculations regarding the candidate renewable resource, i.e. the renewable resources that RESOLVE can pick from to optimize the buildout. The worksheet contains the renewable potential by RESOLVE resource (drawn from the REN_Supply_Curve worksheet), the forced renewable build (candidate resources that the user can force to be built), and the annualized fixed costs per kW of installed capacity for each of these resources, including transmission costs if applicable. Please note that for biomass, small hydro, and geothermal, the annualized fixed costs are adjusted upwards to take into account that RESOLVE models these resources to have a 100% capacity factor, while in reality capacity factors range from 53% to 88%.
REN_Supply_Curve	This worksheet contains a list of the total renewable supply curve, which is synced with the latest RPS calculator version. It is used to calculate the total potential by RESOLVE resource, as well as the average capacity factor and cost. The latter is dependent on which of the cost settings is chosen in the controls tab (a macro needs to be rerun to update these costs).
REN_Tx_Costs	This worksheet contains all data and calculations regarding transmission costs. It contains the transmission cost for out-of-state (OOS) renewable resources, as well as full capacity deliverability status (FCDS) capacity limits and costs, and energy only (EO) capacity for each of the transmission zones. Last, it contains the mapping of Super CREZ/WREZ to RESOLVE zone, which is used to determine the potential by RESOLVE zone from the renewable supply curve.
REN_Profiles	This worksheet contains all data and calculations regarding the renewable profiles. It contains hourly shapes for the 37 modeled days for each of the candidate renewable resources, as well as the planned (& existing) resources.
REN_Existing_Resources	This worksheet is a list of all existing renewable resources. It is used in the REN_Baseline worksheet to calculate the total amount of planned renewables by zone and type.
CONV_Baseline	This worksheet contains the installed capacity by year for each conventional resource for each of the RESOLVE zones. For the CAISO zone, these numbers are based on the data in the CONV_CAISO_Gen_List worksheet. For the other zones, these are hardcoded values based on the 2026 Common Case.
CONV_Candidate	This worksheet contains the annualized fixed costs for the conventional candidate resources, i.e. the thermal resources

Input File	Description
	that RESOLVE can decide to build. These are pulled from the tables in the COSTS_Costs_Table worksheet.
CONV_OpChar	This worksheet contains all data and calculations regarding the operating characteristics of the conventional fleet of each RESOLVE zone. For computational reasons, the thermal fleet is represented as a limited set of units that represent the weighted average for each generator class. For the CAISO generators, most of the data is pulled from the CONV_CAISO_Gen_List worksheet.
CONV_CAISO_Gen_List	This worksheet contains a list of all CAISO generators, including operating characteristics such as heat rate and Pmin. It is mostly based on the CAISO NQC list.
HYD_OpChar	This worksheet contains hydro operating characteristics for each of the RESOLVE zones. For each of the 37 modeled days, it specifies a daily hydro budget, a minimum generation constraint, and a maximum generation constraint.
STOR_Inputs	This worksheet contains all data and calculations regarding storage inputs. It contains the round-trip efficiency, minimum duration, planned storage build, and resource potential. It also contains the annualized fixed costs for the candidate storage resources for both the energy part of storage (e.g. pumped storage reservoir, Li-cells, flow battery tanks) and the capacity part (e.g. pumped storage turbine, Li-ion inverter and power electronics). These costs are pulled from the tables in the COSTS_Costs_Table worksheet.
DR_Conventional	This worksheet contains all data and calculations regarding the available planned (existing) demand response programs, broken out by utility. It also includes the assumed supply curve for new conventional DR.
DR_Advanced	This worksheet contains all data and calculations regarding flexible demand responses modeled in RESOLVE
COSTS_Cost_Table	This worksheet contains a list of tables with calculated costs for each of the resource types as defined in the COSTS_Resource_Char worksheet. The numbers in these tables are entered by a macro that loops over each of the resource types in the COSTS_Resource_Char worksheet and calculates annual levelized fixed costs using pro forma calculations. To refresh these costs, press the “Refresh Levelized Costs” macro button at the top left.
COSTS_Resource_Char	This worksheet contains all data and calculations regarding the resource costs. A list of inputs is provided in the yellow-shaded cells. The costs can be recalculated by pressing the “Refresh All Levelized Costs” macro button at the top left. This will spit out a list of numbers (blue font) in the green-shaded cells, as well as fill out the tables in the COSTS_Costs_Table worksheet.
COSTS_Pro_Forma	This worksheet contains the pro forma calculations used to determine annual levelized fixed costs for each of the resources. When the “Refresh All Levelized Fixed Costs” button is clicked, the resource pro forma will be evaluated for each resource for each year of interest and the final output will be pasted in the COSTS_Cost_Table worksheet and the

Input File	Description
	COSTS_Resource_Char worksheet.

1.3 Conventions

The following conventions are used in RESOLVE and/or in this documentation:

+ All costs are reported in **2016 dollars**.
+ All levelized costs are assumed to be **levelized in real terms** (i.e., a stream of payments over the lifetime of the contract that is constant in real dollars).
+ Within RESOLVE and throughout this document, the term **"Baseline Resources"** is used to designate the portion of the portfolio that is exogenous, generally reflecting either existing resources and future resources planned by the utilities; the term **"Selected Resources"** refers to those resources that are chosen by RESOLVE as part of the portfolio optimization.

1.4 Document Contents

The remainder of this document is organized as follows:

+ Section 2 (Load Forecast) documents the assumptions and corresponding sources used to derive the forecast of load in CAISO and the WECC, including the impacts of demand-side programs, load modifiers, and the impacts of electrification;
+ Section 3 (Baseline Resources) summarizes RESOLVE's assumptions on "baseline" resources—resources that are treated as exogenous to RESOLVE;
+ Section 4 (Candidate Resources) discusses assumptions used to characterize the candidate resources that RESOLVE can select for inclusion in the optimized, least-cost portfolio;
+ Section 5 (Operating Assumptions) presents the assumptions used to characterize the operations of each of the resources represented in RESOLVE's internal hourly production simulation model;
+ Section 6 (Resource Adequacy Requirements) discusses the constraints imposed on the RESOLVE portfolio to ensure system and local reliability needs are met, as well as assumptions regarding the contribution of each resource towards these requirements;

+ **Section 7 (Greenhouse Gas Constraint)** discusses assumptions used in RESOLVE to characterize constraints on portfolio greenhouse gas emissions.

2 Load Forecast

2.1 CAISO Zone

Within CAISO, the annual load forecast is explicitly represented as a forecast of “Baseline Consumption” with a series of “demand-side modifiers.” These modifiers include:

- Electric vehicles;
- Building electrification;
- Behind-the-meter PV;
- Non-PV self-generation;
- Energy efficiency; and
- TOU rate impacts.

The CAISO load forecast is decomposed into these components so that the distinct hourly profile of each of these factors can be represented explicitly in RESOLVE. The profiles used to represent each component of the forecast are discussed in Section 5.2.1.

The primary source for load forecast inputs in RESOLVE is the CEC’s 2016 Integrated Energy Policy Report (IEPR) Demand Forecast.[1] For several the demand-side modifiers, alternative levels of achievement can be selected as alternative scenario settings within RESOLVE; where this functionality exists, the sources of alternative assumptions are discussed.

All demand forecasts presented in this section reflect demands at the customer meter. Within RESOLVE, these demand forecasts are subsequently grossed up for assumed transmission & distribution losses of

[1] Most inputs to RESOLVE were extracted from Forms 1.1c, 1.5a, 1.5b, and 1.2.

7.3%, based on the average losses across the CAISO footprint assumed in the CEC's 2016 IEPR Demand Forecast.

2.1.1 BASELINE CONSUMPTION

Within RESOLVE, the term "Baseline Consumption" is used to refer to a counterfactual forecast of the consumption of electricity, capturing forecast economic and demographic changes in California, in the absence of load modifiers. The Baseline Consumption used in RESOLVE is derived from the retail sales reported in the CEC's 2015 IEPR Demand Forecast along with accompanying information on the magnitude of embedded load modifiers. The derivation of this Baseline Consumption from the retail sales forecast is shown in Table 2.

Table 2. Derivation of "Baseline Consumption" from CEC 2016 IEPR Demand Forecast (GWh)

Component	2018	2022	2026	2030
CEC 2016 IEPR Retail Sales	209,522	208,903	207,748	*(last year of CEC 2016 IEPR Demand Forecast is 2027)*
+ Mid AAEE	+5,652	+11,829	+17,990	
+ Non-PV Self Generation	+13,516	+13,857	+14,058	
+ Behind-the-Meter PV	+10,226	+13,983	+20,191	
- Electric Vehicles	-1,123	-2,808	-5,626	
- Building Electrification	-187	-575	-917	
Baseline Consumption	**237,605**	**245,189**	**253,444**	***261,760***

Values shown in italics are extrapolated based on the 5-year compound average growth rate between 2022-2027

2.1.2 ELECTRIC VEHICLES

RESOLVE includes three options for forecasts of the future load impact of vehicle electrification. The first forecast is based directly on the embedded assumptions of the CEC 2016 IEPR Mid Demand forecast. The second two options capture forecasts of transportation electrification included in CARB's 2016 Scoping Plan[2]: (1) the "SP" option reflects CARB's adopted Scoping Plan scenario, which includes 3.6 million light duty electric vehicles in California by 2030; and (2) the "Alt1" option represents CARB's Alternative 1 scenario, which includes a total of 4 million light duty vehicles by 2030. Both of CARB's

[2] CARB's 2016 Scoping Plan is available for download here: **https://www.arb.ca.gov/cc/scopingplan/scopingplan.htm**

scenarios also include some electrification of the medium- and heavy-duty vehicle fleets. These three alternative forecasts are shown in Table 3.

Table 3. Electric vehicle forecast options (GWh)

RESOLVE Scenario Setting	2018	2022	2026	2030
CEC 2016 IEPR	1,123	2,808	5,626	*8,552*
CARB Scoping Plan – SP	716	1,997	4,931	8,483
CARB Scoping Plan – Alt1	713	1,960	5,069	9,039

Values shown in italics are extrapolated based on the 5-year linear growth rate between 2022-2027 (IEPR) and 2025-2030 (Scoping Plan)

2.1.3 BUILDING ELECTRIFICATION

As with electric vehicles, RESOLVE includes three options for forecasts of the future load impact of building electrification: one based on the forecast embedded in the CEC 2016 IEPR and two based on CARB's 2016 Scoping Plan scenarios. CARB's "SP" scenario includes no incremental building electrification measures and so is assumed to be identical to the CEC 2016 IEPR forecast. CARB's "Alt1" scenario assumes some incremental electrification in residential cooking, residential and commercial HVAC, and residential and commercial water heating. These forecasts are shown in Table 4.

Table 4. Building electrification forecast options (GWh)

RESOLVE Scenario Setting	2018	2022	2026	2030
CEC 2016 IEPR[3]	187	575	917	*1,232*
CARB Scoping Plan – SP	187	575	917	*1,232*
CARB Scoping Plan – Alt1	187	575	3,874	*13,183*

Values shown in italics are extrapolated based on the 5-year linear growth rate between 2022-2027 (IEPR) and 2025-2030 (Scoping Plan)

[3] Based on correspondence with the CEC, the forecast of building electrification loads is assumed not to have changed since the 2015 IEPR. The level of building electrification load embedded in the 2015 Demand Forecast is based on "CAISO Load Modifiers Mid Baseline-Mid AAEE," available at: http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN209995_20160127T095507_CAISO_Load_Modifiers_Mid_BaselineMid_AAEE.xlsx.

2.1.4 BEHIND-THE-METER PV

RESOLVE includes three options for behind-the-meter PV adoption, each of which is based on the CEC's 2016 IEPR Demand Forecast. These options—Low, Mid, and High[4]—correspond to installed capacities of behind-the-meter PV of 9,300 MW, 15,900 MW, and 20,100 MW among CAISO LSEs by 2030, respectively. These forecasts are shown in Table 5.

Table 5. Behind-the-meter PV forecast options (GWh)

RESOLVE Scenario Setting	2018	2022	2026	2030
CEC 2016 IEPR – Low PV	9,741	11,163	13,297	*15,627*
CEC 2016 IEPR – Mid PV	10,226	13,983	20,191	*26,819*
CEC 2016 IEPR – High PV	10,480	15,733	24,470	*33,801*

Values shown in italics are extrapolated based on the average linear growth rate between 2022 and 2027.

2.1.5 NON-PV SELF GENERATION

The forecast of non-PV self-generation (i.e., on-site combined heat & power) is based on the CEC 2016 IEPR Demand Forecast. This assumption is shown in Table 6. Alternative levels of on-site CHP adoption are not considered in RESOLVE.

Table 6. Forecast of non-PV on-site self-generation (GWh)

Scenario Setting	2018	2022	2026	2030
CEC 2016 IEPR	13,516	13,857	14,058	*14,096*

Values shown in italics are assumed to remain constant at the level forecast in 2027.

2.1.6 ENERGY EFFICIENCY

RESOLVE includes four options for varying levels of energy efficiency achievement among CAISO load-serving entities:

[4] RESOLVE's Low PV forecast is based on the IEPR High Demand forecast; the High PV forecast is based on the IEPR Low Demand forecast. The naming of the IEPR forecasts corresponds to the relative level of retail load in each of the forecasts (higher amounts of customer PV yields lower retail load).

+ **CEC 2016 IEPR – No AAEE:** Based on the CEC's 2016 IEPR Demand Forecast, this forecast assumes no achievement of the "Additional Achievable Energy Efficiency" (AAEE) beyond current committed programs.
+ **CEC 2016 IEPR – Mid AAEE:** Based on the CEC's 2016 IEPR Demand Forecast, this forecast assumes that utilities continue to procure all cost-effective energy efficiency as identified under current programs.
+ **CEC 2016 IEPR – Mid AAEE + AB802:** In addition to including the load impact of the Mid AAEE, this option includes additional load reduction measures associated with savings enabled by AB802, which allows utilities to claim savings for programs that bring existing buildings up to code. The potential savings associated with such programs were identified by Navigant in a 2016 report funded by the CPUC.[5]
+ **SB350 – Mid AAEE x2:** In addition to the including the load impact of the Mid AAEE, this option includes additional savings that would achieve the 2030 SB350 goal of a doubling of energy efficiency. The incremental efficiency savings included in this option is derived from the RPS Calculator v.6.2, which includes load scenarios that reflect both the Mid AAEE and its doubling. To date, no analysis has identified the specific programs or measures that might be included in this wedge.

The assumed reductions in retail load corresponding to each of these levels of achievement are shown in Table 7.

Table 7. Energy efficiency forecast options (GWh)

RESOLVE Scenario Setting	2018	2022	2026	2030
CEC 2016 IEPR – No AAEE	—	—	—	—
CEC 2016 IEPR – Mid AAEE	5,652	11,829	17,990	24,006
CEC 2016 IEPR – Mid AAEE + AB802	6,974	15,574	24,130	32,570
SB350 – Mid AAEE x2	6,098	16,431	30,540	39,535

[5] *AB802 Technical Analysis: Potential Savings Analysis*. Available at: **http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11189**.

2.1.7 TIME-OF-USE RATE IMPACTS

RESOLVE includes four options representing differing impacts of residential time-of-use (TOU) rate implementation on retail load:

- **None:** assumes no change in load shape.
- **Low (Christensen Scenario 3):** based on the results of *Statewide Time-of-Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report*, a study conducted by Christensen Associates. In this study, "Scenario 3" assumes 30% residential participation in TOU rates by 2025.
- **Mid (MRW Scenario 4):** based on the results of *Potential Load Impacts of Residential Time of Use Rates in California*, a study conducted by MRW & Associates. In this study, "Scenario 4" assumes 80% residential participation in TOU rates by 2025.
- **High (MRW Scenario 4 x1.5):** in this scenario, the load impacts from the "Mid" case are multiplied by a factor of 1.5. This scenario is intended to capture the potential impacts of even more aggressive TOU pricing patterns than the "Mid" case.

The two studies referenced above are summarized in the *Joint Agency Staff Paper on Time-of-Use Load Impacts*.[6] The load impacts are summarized in Table 8. Because TOU rates primarily impact the timing of consumption, rather than the absolute total amount of energy consumed, the aggregate load impacts shown in Table 8 small. The corresponding impacts upon the load shape are discussed in Section 5.2.1.4.

Table 8. Residential TOU rate implementation load impacts (GWh)

RESOLVE Scenario Setting	2018	2022	2026	2030
None	—	—	—	—
Low (Christensen Scenario 3)	-31	-31	-31	-31
Mid (MRW Scenario 4)	-66	-66	-67	-67
High (MRW Scenario 4 x1.5)	-99	-99	-100	-100

[6] Available at: http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN210253_20160209T152348_Joint_Agency_Staff_Paper_on_TimeofUse_Load_Impacts.pdf

2.2 Other Zones

Demand forecasts for other zones in RESOLVE are developed from two sources. The CEC's 2016 IEPR Demand Forecast is used for each of the other zones within California (LADWP, BANC, and IID).[7] For the external load areas (the Pacific Northwest and the Southwest), TEPPC's 2026 Common Case is used as the basis for load projections. The load forecasts for each external zone, shown in Table 9, have been grossed up for transmission & distribution losses.

Table 9. Demand forecasts for external regions in RESOLVE (GWh)

Region	2018	2022	2026	2030
BANC	18,768	19,255	19,943	*20,646*
IID	3,891	4,226	4,587	*4,965*
LADWP	28,045	28,235	29,161	*30,142*
PNW	243,947	253,078	262,551	*272,378*
SW	154,196	161,004	168,114	*175,537*

[7] See Table 32 for detail on the zonal topology used in RESOLVE

3 Baseline Resources

Within RESOLVE, a portion of the generation fleet is specified exogenously, representing the resources that are assumed to be existing over the course of the analysis; these **"Baseline Resources"** are included by default in the portfolio optimized by RESOLVE. The set of Baseline Resources generally includes (1) existing generators, net of expected future retirements; (2) specific future generation resources with sufficient likelihood to include for planning purposes; and (3) generic future resources needed to meet policy and reliability targets outside of CAISO.

3.1 Conventional Generation

Any non-renewable, thermal resource is referred to as conventional generation. For computational reasons, the thermal fleet in RESOLVE is represented by a limited set of resource classes by zone that represent the weighted average for each resource class in that zone. For each zone, the following 5 resource classes are present: Nuclear, Coal, CHP, CCGT, and Peaker. To more accurately reflect different classes of gas generators in the CAISO zone, CAISO's gas generators are further divided into subcategories:

- The **"CHP"** category represents non-dispatchable cogeneration facilities, which are modeled as must-run baseload resources within RESOLVE.
- CCGT generators are divided into two subcategories: a low heat rate type (**"CAISO_CCGT1"**) and a high heat rate type (**"CAISO_CCGT2"**).
- Peaker generator are divided into two subcategories: a low heat rate type (**"CAISO_Peaker1"**) and a high heat rate type (**"CAISO_Peaker2"**).
- The **"CAISO_ST"** class is used to represent the existing fleet of steam turbines, most of which are scheduled to retire by 2020 to achieve compliance with the State Water Board's Once-Through-Cooling regulations.

+ **"CAISO_Reciprocating_Engine"** represents the existing reciprocating engines on the CAISO system.

Two additional categories of gas generation, **"CAISO_Aero_CT"** and **"CAISO_Advanced_CCGT,"** are represented in RESOLVE but are used only to represent candidate resources and are not used to reflect the capabilities of the existing fleet.

3.1.1 CAISO

The Baseline Conventional Resources included in the portfolio of the CAISO load serving entities is derived from the 2017 CAISO NQC List[8], as shown on the CONV_CAISO_Gen_List worksheet. The data from the NQC list is supplemented with additional information from the CAISO Master List, the TEPPC 2026 Common Case, and the CARB Scoping Plan. E3 manually assigned the appropriate thermal generator type to each of the entries in the NQC list. The resulting annual installed capacity by resource class is shown in Table 10.

By default, RESOLVE assumes that thermal generators will remain online in perpetuity unless they have formally announced intentions to retire, which results in the Baseline thermal fleet remaining relatively stable over time (with the exception of the retirement of the aging once-through-cooling steam generators in 2020). However, RESOLVE also includes functionality to accelerate retirements of the thermal fleet according to assumptions of the economic useful lifetime. Users may select an assumed plant lifetime of 20, 25, or 30 years; this assumption is applied to all flexible gas generators and can be used to model accelerated retirements as shown in Table 10. Note that where an announced retirement conflicts with an assumed plant lifetime, the announced retirement date is assumed to take precedence.

Table 10. Baseline Conventional Resources in the CAISO balancing area (MW)

Scenario Setting	Resource Class	2018	2022	2026	2030
Default	CHP*	1,685	1,685	1,685	1,685
	Nuclear**	2,922	2,922	622	622
	CCGT1	12,419	13,703	13,703	13,703
	CCGT2	2,974	2,974	2,974	2,974

[8] Available here: http://www.caiso.com/Documents/2017NetQualifyingCapacity-ResourceAdequacyResources.html

Scenario Setting	Resource Class	2018	2022	2026	2030
	Peaker1	5,195	5,555	5,555	5,555
	Peaker2	2,859	2,729	2,729	2,729
	Advanced_CCGT	—	—	—	—
	Aero_CT	—	—	—	—
	Reciprocating_Engine	263	263	263	263
	ST	6,416	652	652	652
	Total	**34,734**	**30,484**	**28,184**	**28,184**
Accelerated Retirements	CHP*	1,685	1,685	1,685	1,685
	Nuclear**	2,922	2,922	622	622
	CCGT1	12,419	13,507	11,835	5,995
	CCGT2	2,974	2,974	2,815	2,003
	Peaker1	5,195	4,706	4,530	4,171
	Peaker2	2,859	1,841	1,459	744
	Advanced_CCGT	—	—	—	—
	Aero_CT	—	—	—	—
	Reciprocating_Engine	263	255	163	163
	ST	6,416	12	—	—
	Total	**34,734**	**27,903**	**23,108**	**15,108**

** CHP, which represents the non-dispatchable cogeneration units on the CAISO system, is modeled based on its NQC rather than its nameplate capacity, as large portions of these resources are typically used to meet on-site loads and are not exported to the grid.*

***Diablo Canyon is assumed to retire between 2024 & 2025. The remaining nuclear capacity shown thereafter represents the share of Palo Verde contracted to CAISO LSEs, which is modeled as located within CAISO in RESOLVE.*

In the Controls tab, one of the scenario toggles allows the user to enforce early retirement of the thermal fleet. A second toggle lets the user specify how many years after the commercial operations date (as specified in the CAISO_Gen_List worksheet) thermal plants are forced to retire.

3.1.2 OTHER ZONES

For external zones, the assumed committed thermal generation fleet is based on the assumptions of the TEPPC 2026 Common Case. The Common Case is used to characterize the existing fleet in each region as well as anticipated future changes, including announced retirements of coal generators and near-term planned additions included in utility integrated resource plans. These assumptions are summarized in

Table 11. To ensure resource adequacy in each region in spite of significant retirements in the coal fleet, RESOLVE assumes that CCGTs are added in each region such that the total installed capacity of the thermal fleet does not decrease below its present level.

Table 11. Baseline conventional resources in external zones (MW)

Zone	Resource Class	2018	2022	2026	2030
NW	Nuclear	1,170	1,170	1,170	1,170
	Coal	10,765	8,896	8,226	8,226
	CCGT	9,594	11,133	12,133	12,218
	Peaker	3,327	3,657	3,327	3,243
	Subtotal, NW	**24,856**	**24,856**	**24,856**	**24,856**
SW	Nuclear*	2,858	2,858	2,858	2,858
	Coal	9,101	8,097	7,449	7,449
	CCGT	19,863	20,571	20,887	21,276
	Peaker	8,586	9,197	10,759	10,371
	Subtotal, SW	**40,408**	**40,723**	**41,953**	**41,953**
LDWP	Nuclear*	457	457	457	457
	Coal	1,800	1,800	1,800	—
	CCGT	1,936	1,969	2,413	4,213
	Peaker	2,759	2,727	2,283	2,283
	Subtotal, LDWP	**6,952**	**6,952**	**6,952**	**6,952**
IID	CCGT	255	255	255	255
	Peaker	634	814	814	814
	Subtotal, IID	**889**	**1,069**	**1,069**	**1,069**
BANC	CCGT	1,874	1,874	1,874	1,874
	Peaker	891	891	891	891
	Subtotal, BANC	**2,765**	**2,765**	**2,765**	**2,765**

** In RESOLVE, Palo Verde is split up and modeled in zones according to its contractual ownership shares. This results in portions of the plant being modeled in the Southwest (72.6%), CAISO (15.8%), and LDWP (11.6%).*

3.2 Renewables

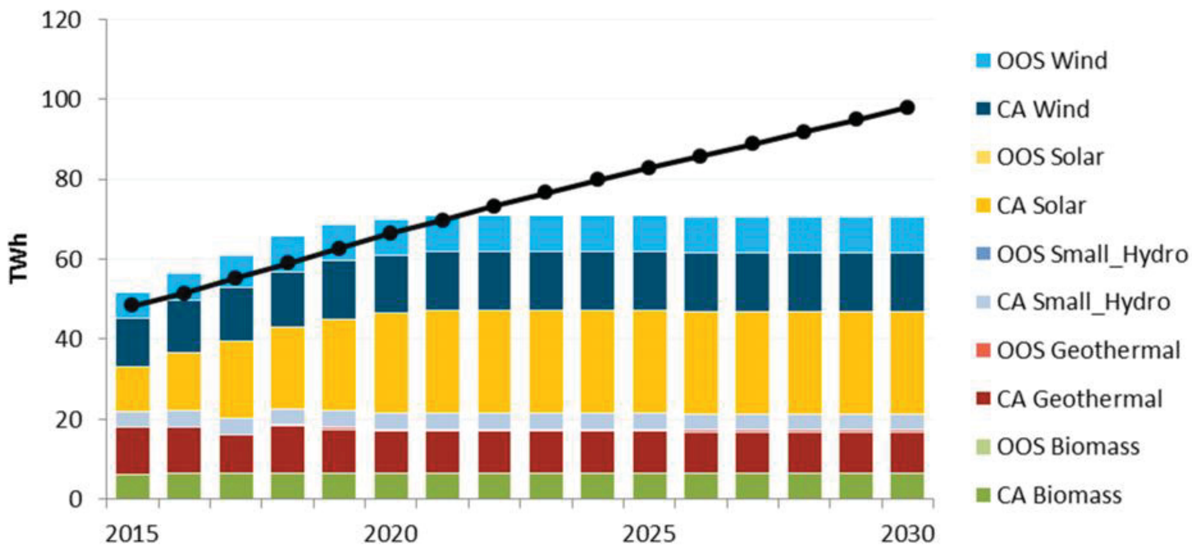
3.2.1 CAISO

The Baseline Renewable Resources included in the portfolio of the CAISO load serving entities includes both (1) existing resources under contract to CAISO LSEs, and (2) resources under development with CPUC-approved contracts to the three investor-owned utilities. This information is compiled from multiple sources:

+ **CPUC IOU Contract Database:** The CPUC maintains a database of all of the IOUs' active and past contracting activities for renewable generation. Utilities submit monthly updates to this database with changes in contracting activities; the IRP relies on information submitted to the contract database by the utilities in October 2016.
+ **CEC POU Contract reports:** Publicly owned utilities submit annual updates to the CEC summarizing their renewable contracting activities. These reports provide detail on the facilities under contract to each POU and the expected duration of those contracts.
+ **CEC Statewide Renewable Net Short spreadsheet:** The CEC tracks the total renewable generation in California, as well as out-of-state resources under contract to California entities, in an effort to quantify the total statewide renewable net short. The generator-specific information in this spreadsheet, including annual historical generation figures (MWh), is used as a supplemental source and a check to ensure that the combined portfolios of the California entities reflects the appropriate total amount of existing renewable generation.

The composition of the portfolio of Baseline Renewable Resources is shown in Figure 1.

Figure 1. Composition of Baseline Resources in renewable portfolios for CAISO LSEs.



3.2.2 OTHER ZONES

3.2.2.1 Other California LSEs

RESOLVE assumes that LSEs in each of the non-CAISO balancing authorities comply with the current RPS statute (50% RPS by 2030). Portfolios of resources for each of these entities are specified exogenously and are based on the existing resource portfolios of each of these entities and assumptions regarding the types of resources that will be used to satisfy the remaining net short for each utility. The existing resources included in each entity's renewable portfolio are derived primarily from the CEC's Statewide Renewable Net Short spreadsheet and contract reports provided by the POUs. Future resources needed to continue compliance with the increasing RPS requirements are based on existing integrated resource plans where available; where such information is unavailable, local solar resources are assumed to fill the renewable net short.

Figure 2. Renewable portfolio for LSEs in BANC

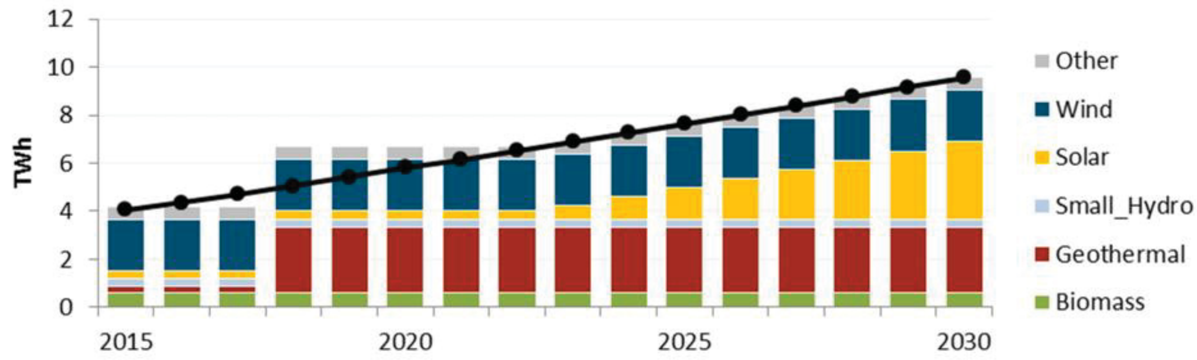


Figure 3. Renewable portfolio for LSEs in IID

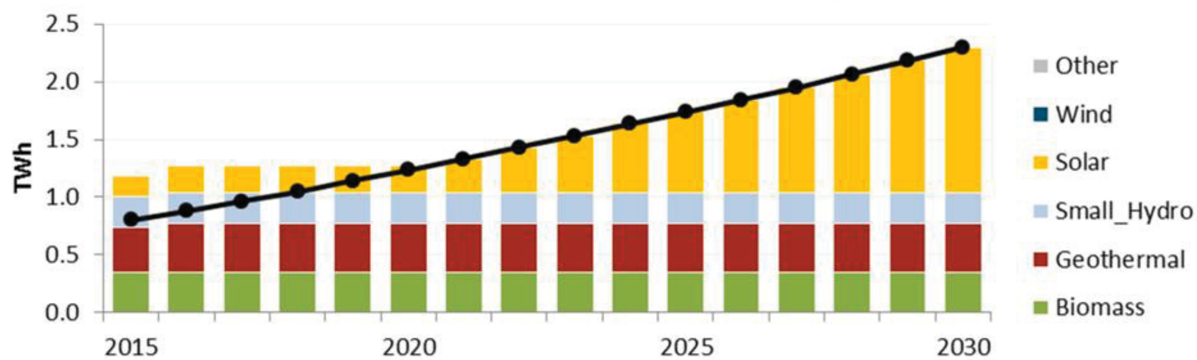
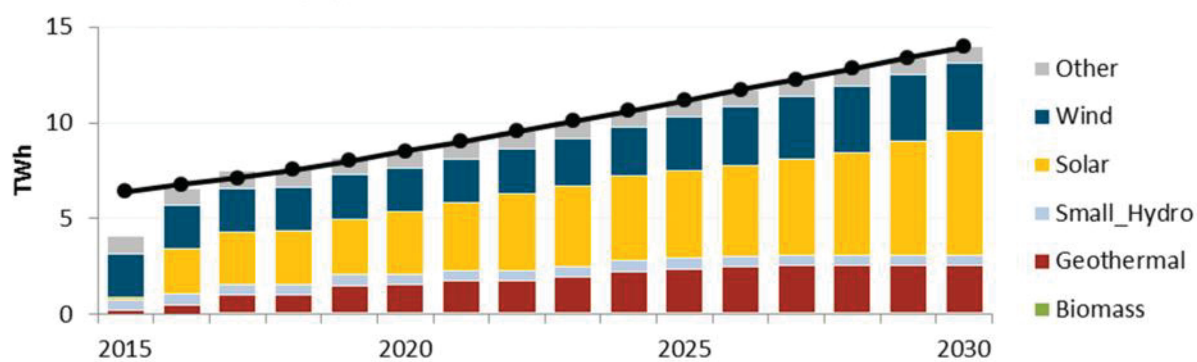


Figure 4. Renewable portfolio for LSEs in LADWP



3.2.2.2 Non-California LSEs

RESOLVE assumes that neighboring states outside of California comply with their applicable RPS statutes. The portfolios of resources procured to meet each state's goals are based on TEPPC's 2026 Common Case, developed by WECC staff with input from stakeholders.

Beyond 2026, renewable resources are added in the Northwest and Southwest to maintain the same level of penetration reached in 2026 across the region. In the Northwest, these generic resources are assumed to be new wind generation; in the Southwest, new generic resources beyond 2026 are assumed to be solar PV.

The renewable portfolios for the Northwest and Southwest are shown in Figure 5 and Figure 6, respectively.

Figure 5. Renewable portfolio for LSEs in the Northwest, based on 2026 Common Case.

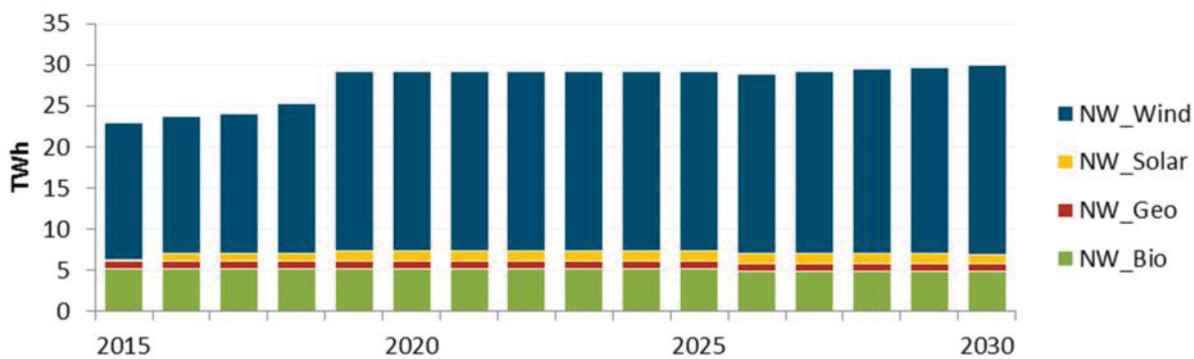
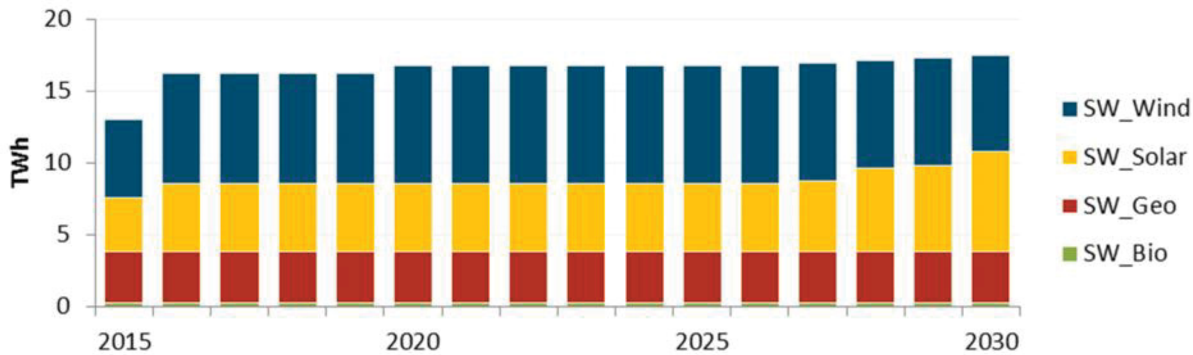


Figure 6. Renewable portfolio for LSEs in the Southwest, based on 2026 Common Case.



Some of the resources in the TEPPC Common Case located outside of California represent resources under long-term contract to California LSEs. Since these resources are captured in the portfolios of CAISO and other California LSEs, they are removed from the set of resources assumed to meet the policy goals of the non-California LSEs. The list of resources located outside of California but excluded for this reason is based on information and spreadsheets provided by WECC staff and stakeholders is shown in Table 12.

Table 12. TEPPC 2026 Common Case renewable plants outside of CA attributed to California loads.

TEPPC ID	MW	TEPPC ID	MW	TEPPC ID	MW	TEPPC ID	MW
Ajo Solar	132	EnelCoveFort1-1	16	MesquiteSolar111	16	RpsCA-0059	150
Amercian Falls Solar II	140	EnelCoveFort1-2	16	MesquiteSolar112	16	RpsCA-0067	116
American Falls Solar I	140	Foothills Solar 1	116	MesquiteSolar12	16	RpsCA-0068	50
ArlingtonValleyPV1	127	Foothills Solar 2	116	MesquiteSolar13	10	Sand Ranch	100
ArlingtonValleyPV2	127	Four Corners	10	MesquiteSolar14	16	Sand Ridge	9
ArlingtonWind	103	Four Mile Canyon	10	MesquiteSolar15	16	Sandstone Solar	11
Avalon Solar II	1	Ft. Huachuca	4	MesquiteSolar16	8	Simco Solar	140
Benson Creek Wind (OR)	40	Gila Bend	174	MesquiteSolar17	16	South_Hurlburt3	145
BigHorn1	200	GlacierWind1	107	MesquiteSolar18	12	South_Hurlburt4	145
BigHorn2	50	GlacierWind2	104	MesquiteSolar19	16	Springerville Expansion	3
BlackspringRidge	300	Goodnoe_Hills1	94	MilfordWind1-1	145	Star_Point	99
Boise City Solar	140	Goodnoe_Hills2	34	MilfordWind1-2	59	Stateline	100
CaithDixiVally1	19	Goshen2-JollyHills-1	90	MilfordWind2	102	TGP_1	130
CaithDixiVally2	19	Goshen2-JollyHills-2	39	Moapa Southern Paiute Solar	9	ThermoNo1-2	14
CaithDixiVally3	19	Grand View PV Solar Two	140	Mountain Home Solar	140	Three Mile Canyon	100
CaithnessDixieValley	50	Graycliff Wind Prime	10	Murphy Flat Power	140	Thunderegg Solar	140
Clark Solar 1	140	GREEN RIDGE POWER (JACKSON)	55	Musselshell Wind Two	107	TietonDamHydroUNIT1	7

TEPPC ID	MW	TEPPC ID	MW	TEPPC ID	MW	TEPPC ID	MW
Clark Solar 2	140	Grove Solar Center LLC	140	NorthHurlburt1	133	TietonDamHydroUNIT2	7
Clark Solar 3	140	Halkirk1	76	NorthHurlburt2	133	Torch Red Horse	10
Clark Solar 4	140	Halkirk2	74	NRG Solar- Avra Valley	3	Tucannon River Wind	9
Comanche Solar	9	Hooper Solar	9	Open Range Solar (OR)	140	Tuolumne1	68
CopperMtnPV2_1	30	Huerfano River Wind	152	Orchard Ranch Solar	140	Tuolumne2	68
CopperMtnPV2_2	30	Hyder II	132	Pacific Canyon	100	Vale Solar (OR)	140
CopperMtnPV2_3	34	Hyline Solar Center	140	Patua1A1	16	Vantage	96
CopperMtnPV2_4	30	Jett Creek Wind (OR)	40	Patua1A2	16	Wild_Rose	25
CopperMtnPV2_5	30	Kingman PPA	3	Patua1A3	16	Willow Creek	78
CopperMtnPV48_2	8	KlondikeWind3_1	224	Patua1A4	16	WillowCreekEC	72
CopperMtnPV48_3	10	KlondikeWind3_2	77	Patua1A5	16	WindyFlats1	202
CopperMtnPV48_4	10	LeaningJunipr1	101	Patua1A6	16	WindyFlats2	60
CopperMtnPV48_5	10	Limon III	100	PebbleSprings	99	WindyFlats3	99
CopperMtnPV48_6	10	LindenWind	50	Pocatello Solar 1	140	Wolverine Creek	19
Durbin Creek Wind (OR)	40	Meadowlake Solar PV	4	Prospector Wind (OR)	40	WyomingWindGE15	144
Echanis_Wind	104	MesquiteSolar11	16	Railroad Solar Center	140		
Elkhorn_Valley	100	MesquiteSolar110	12	RimRockEnergy	189		

3.3 Large Hydro

The existing large hydro resources in each region of the analysis are assumed to remain unchanged over the timeline of the analysis. The total installed capacity of large hydro and pumped storage resources in each region are shown in Table 13. The large hydro resources as shown in this table represent the resources physically located in each region with the exception of Hoover, which is split among the CAISO, LADWP, and SW regions in proportion to its ownership shares.

Table 13. Assumed large hydro resources in RESOLVE (MW)

Region	Non-Hoover Resources (MW)	Hoover Share (MW)	Total (MW)
BANC	2,742	—	2,742
CAISO*	7,047	797	7,844
IID	85	—	85
LADWP*	1,572	366	1,939
NW	34,379	—	34,379
SW*	3,073	917	3,991

** Each of these regions include a share of Hoover's total generating capability (2,080 MW) in proportion to their ownership shares: CAISO (38.3%), LADWP (17.6%), and SW (44.1%)*

3.4 Energy Storage

3.4.1 PUMPED STORAGE

The existing pumped storage resources in CAISO are based on the CAISO 2017 NQC list; the storage capability of each facility, in MWh, is based on input assumptions in CAISO's 2014 LTPP PLEXOS database. Note that although this number is large, the capability to store energy beyond 12 hours is not directly captured in RESOLVE given the dispatch window of one day at a time. The existing pumped storage resources in CAISO are summarized in Table 14.

Table 14. Existing pumped storage resources in CAISO

Unit	Capacity (MW)	Storage (MWh)
Eastwood	200	5,000
Helms	1,216	184,500
Lake Hodges	40	125
San Luis	374	100,000
Total	**1,832**	**289,625**

3.4.2 STORAGE MANDATE

RESOLVE includes multiple options for assumptions on the Baseline Resources for energy storage. These options, shown Table 15, allow the user to model three different levels of storage penetration (in each case, RESOLVE will add additional storage resources if it finds it is cost-effective to do so).

Table 15. Options for planned storage resources in RESOLVE (MW)

Scenario Setting	2018	2022	2026	2030
No Mandate	470	470	470	470
1,325 MW by 2020	835	1,325	1,325	1,325
1,325 MW by 2020 + 500 MW	1,135	1,825	1,825	1,825

The storage resources included as Baseline Resources in RESOLVE are, by default, assumed to have an average duration of four hours.

3.5 Demand Response

RESOLVE treats the IOUs' existing demand response programs as Baseline Resources; the assumed peak load impact for each utility's programs are based on its 2016 Demand Response Load Impacts Report filed in the demand response proceeding. Two options for assumptions on existing demand response programs are available:

+ **Reliability & Economic Programs** assumes that the current suite of reliability and economic demand response programs are continued indefinitely at current levels of load impact; and
+ **Reliability Programs Only** assumes that economic demand response programs are discontinued after the current funding cycle (2018-2022), resulting in a reduction in the amount of Baseline DR resources after 2022.

The load impacts associated with each of these scenario settings are shown in Table 16.

Table 16. Forecast load impact of IOU demand response programs (MW)

Scenario Setting	Region	2018	2022	2026	2030
Reliability & Economic Programs	PG&E	541	541	*541*	*541*
	SCE	1,019	1,019	*1,019*	*1,019*
	SDG&E	56	56	*56*	*56*
	Total	**1,617**	**1,617**	***1,617***	***1,617***
	Total, w/ losses	**1,752**	**1,752**	***1,752***	***1,752***
Reliability Programs Only	PG&E	541	541	*330*	*330*
	SCE	1,019	1,019	*696*	*696*
	SDG&E	56	56	*7*	*7*
	Total	**1,617**	**1,617**	***1,033***	***1,033***
	Total, w/ losses	**1,752**	**1,752**	***1,119***	***1,119***

DR load impacts shown in italics represent assumed load impacts beyond current funding cycle (2018-2022).

4 Candidate Resources

"Candidate resources" represent the menu of options from which RESOLVE can select to create an optimal portfolio. RESOLVE can add multiple different types of resources, including natural gas generation, renewables, energy storage, and demand response. The optimal mix is a function of the relative costs and characteristics of the candidate resources and the constraints that the portfolio must meet.

4.1 Natural Gas

RESOLVE includes multiple technology options for new natural gas generation of varying costs and efficiencies. The natural gas resource classes available to the model and their respective all-in fixed costs, derived from E3's 2014 review of capital costs for WECC, *Capital Cost Review of Power Generation Technologies*,[9] are shown in table below. This cost includes all costs, except variable O&M and fuel costs.

Operational assumptions for these plants are summarized in Section 5.3.1.

Table 17. All-in fixed costs for candidate natural gas resources ($/kW-yr)

Resource Class	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-yr)	All-In Fixed Cost ($/kW-yr)
CAISO_Advanced_CCGT	$1,300	$10	$202
CAISO_Aero_CT	$1,250	$12	$197
CAISO_Reciprocating_Engine	$1,250	$12	$197

[9] Available at: https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf

4.2 Renewables

4.2.1 POTENTIAL

Assumptions on the cost, performance, and potential of candidate renewable resources are based on data developed by Black & Veatch for the CPUC's RPS Calculator v.6.3.[10] Black & Veatch used geospatial analysis to identify potential sites for renewable development in California and throughout the Western Interconnection.For input into RESOLVE, the detailed geospatial dataset developed by Black & Veatch is aggregated into "transmission zones." Within California, transmission zones are groupings of Competitive Renewable Energy Zones (CREZs). These groupings are shown in Figure 7.

The raw technical potential estimates developed by Black & Veatch are filtered through a set of environmental screens to produce the potential assumed available to RESOLVE. RESOLVE includes several options for environmental screens, which were original developed for the RPS Calculator:

+ **Base:** includes RETI Category 1 exclusions only
+ **Environmental Baseline (EnvBase):** includes RETI Category 1 and 2 exclusions
+ **NGO1:** first screen developed by environmental NGOs
+ **NGO1&2:** second screen developed by environmental NGOs
+ **DRECP/SJV:** includes RETI Categories 1 and 2 plus preferred development areas only in the DRECP and SJV
+ **Minimum:** represents the minimum available potential across all screens

The associated potential for each of these environmental screens is summarized in Table 18.

[10] Black & Veatch, *RPS Calculator V6.3 Data Updates*. Available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/LTPP/RPSCalc_CostPotentialUpdate_2016.pdf

Figure 7. In-state transmission zones in RESOLVE.

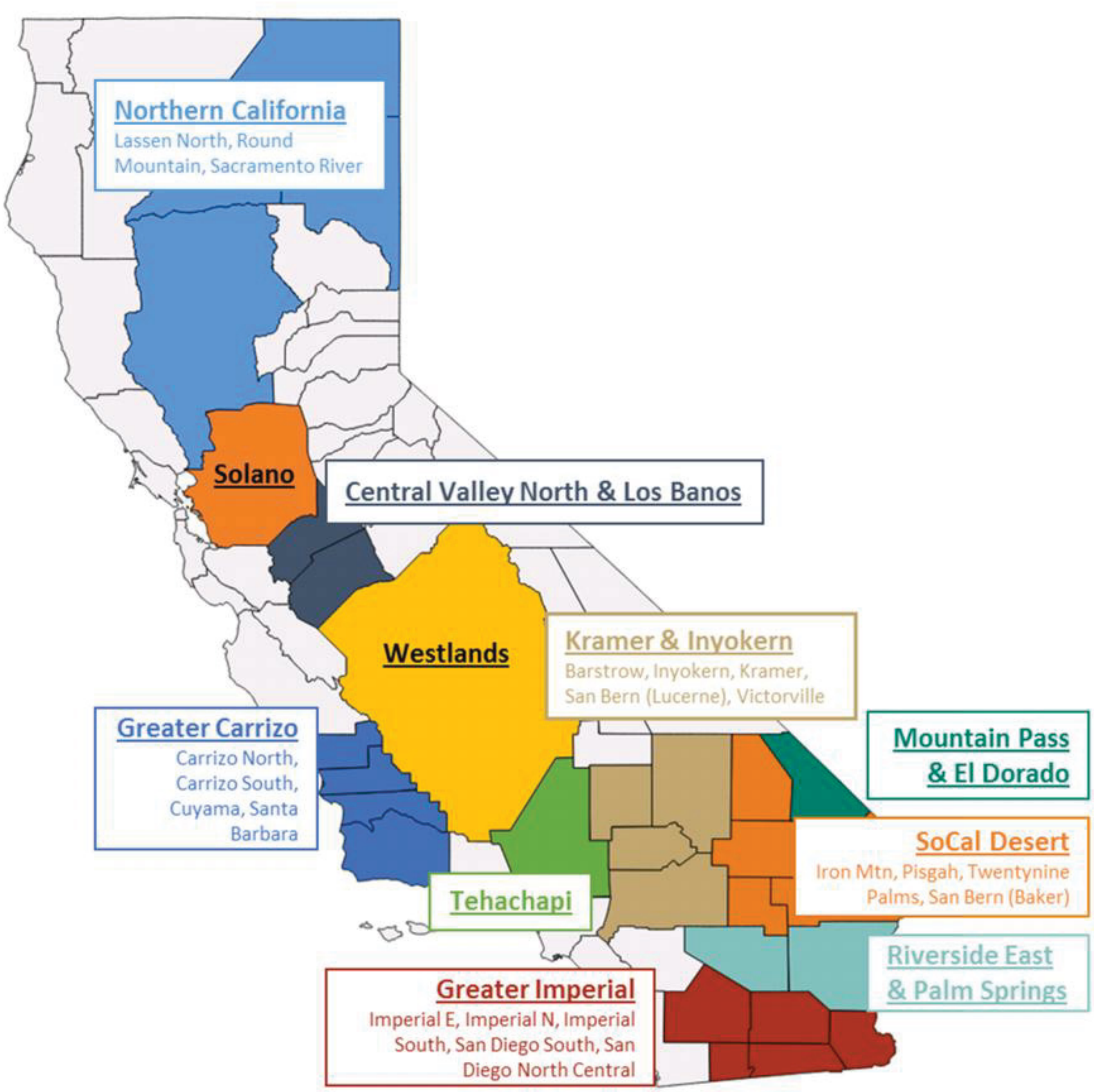


Table 18. California renewable potential under various environmental screens.

Type	Resource	Renewable Potential (MW)					
		Base	Env Base	NGO1	NGO1&2	DRECP/SJV	Minimum
Biomass	InState	—	—	—	—	—	—
Geothermal	Greater Imperial	1,384	1,384	1,384	1,384	1,384	1,384
	Northern California	424	424	424	424	424	424

	Subtotal, Geothermal	**1,808**	**1,808**	**1,808**	**1,808**	**1,808**	**1,808**
Solar	Central Valley North Los Banos	3,988	3,021	3,901	2,477	1,264	1,264
	Distributed	36,605	36,605	36,605	36,605	36,605	36,605
	Greater Carrizo	4,572	3,787	4,540	2,734	3,805	2,734
	Greater Imperial	7,461	4,819	7,366	4,592	8,807	3,617
	Mountain Pass El Dorado	288	15	288	10	62	10
	Northern California	29,319	19,572	28,715	16,192	19,649	16,192
	Riverside East Palm Springs	4,172	2,289	4,145	2,198	14,339	1,420
	Solano	4,693	2,170	4,471	1,483	2,275	1,483
	Southern California Desert	—	—	—	—	8,533	—
	Tehachapi	4,535	3,493	4,464	3,446	1,073	1,073
	Westlands	13,147	11,310	12,661	9,317	15,750	7,643
	Subtotal, Solar	**108,780**	**87,081**	**107,156**	**79,054**	**112,162**	**72,041**
Wind	Central Valley North Los Banos	170	146	126	69	146	69
	Distributed	253	253	253	253	253	253
	Greater Carrizo	1,276	1,096	1,267	908	1,095	908
	Greater Imperial	922	83	919	83	—	—
	Kramer Inyokern	1,381	283	1,314	283	—	—
	Northern California*	—	—	—	—	—	—
	Riverside East Palm Springs	544	42	527	42	42	42
	Solano	1,629	642	1,520	567	643	567
	Southern California Desert	124	48	124	48	—	—
	Tehachapi	934	715	923	704	407	405
	Subtotal, Wind	**7,233**	**3,308**	**6,973**	**2,957**	**2,586**	**2,244**

** Renewable potential for Northern California wind is set to zero across all screens due to both the unproven nature of the resource and expected obstacles in resource permitting*

The available potential for out-of-state resources is also based primarily on Black & Veatch's assessment of renewable resource potential that identifies high-quality resources in Western Renewable Energy Zones (WREZs), which are aggregated to regional bundles. These high-quality resources are assumed to require investments in new transmission to interconnect and deliver to California loads. These estimates of resource potential are supplemented with assumptions regarding the availability of lower-quality renewables that may be interconnected on the existing transmission system.

RESOLVE includes three "screens" for out-of-state resources available in the model's scenario settings:

+ **None:** no out-of-state resources are included in the optimization;

- **Existing Tx Only:** only resources that can be interconnected on the existing transmission system and delivered to California are included in the optimization; and
- **Existing & New Tx:** all out-of-state resources, including those requiring major investments in new transmission, are included in the optimization.

The amount of renewable potential included under each screen is summarized in Table 19; all estimates of potential shown in this table—with the exception of resources assumed to interconnect to the existing transmission system—are based on Black & Veatch's potential assessment.

Table 19. Out-of-state renewable potential under various scenario settings.

Type	Resource	Renewable Potential (MW)		
		None	Existing Tx Only	Existing & New Tx
Geothermal	Pacific Northwest	—	—	832
	Southern Nevada	—	—	320
	Subtotal, Geothermal	**—**	**—**	**1,152**
Solar	Arizona	—	—	19,270
	New Mexico	—	—	166
	Southern Nevada	—	—	37,176
	Utah	—	—	14,414
	Subtotal, Solar	**—**	**—**	**71,026**
Wind	Arizona	—	—	2,900
	Idaho	—	—	6,869
	New Mexico (Existing Tx)	—	500	500
	New Mexico	—	—	34,580
	Pacific Northwest (Existing Tx)	—	1,500	1,500
	Pacific Northwest	—	—	11,072
	Southern Nevada	—	—	442
	Utah	—	—	5,033
	Wyoming	—	—	33,862
	Subtotal, Wind	**—**	**2,000**	**96,758**

4.2.2 COST & PERFORMANCE

The primary source for cost & performance assumptions of renewable generation was developed by Black & Veatch for the RPS Calculator v.6.3 in early 2013; this information has been supplemented by an additional analysis conducted by E3 on the cost and performance of new generation resources for the Western Electricity Coordinating Council (WECC). In particular, because market data suggests a notable reduction in the cost of solar PV since Black & Veatch's assessment, E3's WECC study has been used to update the assumed cost of solar PV resources. The assumptions for renewable resources used in RESOLVE are shown in Table 20 and Table 19 for in-state and out-of-state resources, respectively. The input to RESOLVE is an assumed levelized fixed cost ($/kW-yr) for each resource; this is translated into the levelized cost of energy ($/MWh) in Table 20 and Table 19 for comparability with typical Power Purchase Agreements (PPA) entered into between utilities and third-party developers.

Several conventions and assumptions are worth noting to clarify the assumptions highlighted in these two tables:

+ Note that the increase in the implied levelized cost for wind and solar, notwithstanding the reductions in capital costs assumed between 2018 and 2030, are a result of the expiration of the federal Production Tax Credit (wind), federal Investment Tax Credit (solar), and state property tax exclusion (solar).
+ The capital costs reported in Table 20 reflect AC capital costs for all technologies. For solar PV, an inverter loading ratio of 1.3 is assumed, which implies that DC capital costs are $1.74 and $1.57 per watt in 2018 and 2030, respectively.

Table 20. California renewable resource cost & performance assumptions.

Type	Resource	Capacity Factor	Capital Cost (2016 $/kW)				Implied Levelized Cost of Energy (2016 $/MWh)			
			2018	2022	2026	2030	2018	2022	2026	2030
Biomass	InState	86%	$6,231	$6,231	$6,231	$6,231	$129	$129	$129	$129
Geothermal	Greater Imperial	88%	$5,349	$5,349	$5,349	$5,349	$92	$92	$92	$92
	Northern California	80%	$5,011	$5,011	$5,011	$5,011	$89	$89	$89	$89
Solar *(solar capital costs shown in $/kW-ac)*	Central Valley North Los Banos	30%	$1,908	$1,841	$1,788	$1,699	$53	$52	$69	$67
	Distributed	23%	$3,269	$3,040	$2,886	$2,725	$104	$99	$126	$120
	Greater Carrizo	32%	$1,908	$1,841	$1,788	$1,699	$49	$48	$64	$62
	Greater Imperial	34%	$1,908	$1,841	$1,788	$1,699	$47	$46	$61	$58
	Mountain Pass El Dorado	34%	$1,908	$1,841	$1,788	$1,699	$46	$45	$59	$57
	Northern California	30%	$1,908	$1,841	$1,788	$1,699	$53	$52	$69	$66
	Riverside East Palm Springs	34%	$1,908	$1,841	$1,788	$1,699	$46	$45	$60	$58
	Solano	29%	$1,908	$1,841	$1,788	$1,699	$54	$53	$70	$67
	Southern California Desert	35%	$1,908	$1,841	$1,788	$1,699	$46	$45	$60	$57
	Tehachapi	35%	$1,908	$1,841	$1,788	$1,699	$45	$44	$58	$56
	Westlands	30%	$1,908	$1,841	$1,788	$1,699	$52	$51	$67	$65
Wind	Central Valley North Los Banos	31%	$2,019	$2,004	$1,989	$1,974	$57	$70	$78	$77
	Distributed	28%	$2,499	$2,480	$2,462	$2,443	$88	$100	$108	$107
	Greater Carrizo	31%	$2,063	$2,048	$2,033	$2,018	$60	$73	$80	$80
	Greater Imperial	31%	$2,032	$2,017	$2,002	$1,987	$52	$65	$73	$73
	Kramer Inyokern	32%	$2,028	$2,012	$1,997	$1,983	$61	$73	$81	$81
	Northern California	29%	$2,000	$1,985	$1,970	$1,955	$66	$78	$85	$85
	Riverside East Palm Springs	33%	$2,018	$2,003	$1,988	$1,974	$59	$71	$79	$79
	Solano	30%	$2,022	$2,007	$1,992	$1,977	$61	$73	$81	$81
	Southern California Desert	27%	$2,010	$1,995	$1,980	$1,965	$66	$79	$87	$86
	Tehachapi	33%	$2,119	$2,103	$2,087	$2,072	$55	$67	$75	$75

Table 21. Out-of-state renewable resource cost & performance assumptions

Type	Resource	Capacity Factor	Capital Cost (2016 $/kW)				Implied Levelized Cost of Energy (2016 $/MWh)			
			2018	2022	2026	2030	2018	2022	2026	2030
Geothermal	Pacific Northwest	84%	$4,952	$4,952	$4,952	$4,952	$82	$82	$82	$82
	Southern Nevada	80%	$6,259	$6,259	$6,259	$6,259	$104	$104	$104	$104
Solar *(solar capital costs shown in $/kW-ac)*	Arizona	34%	$1,750	$1,689	$1,640	$1,558	$39	$38	$53	$51
	New Mexico	33%	$1,754	$1,692	$1,644	$1,562	$39	$38	$54	$52
	Southern Nevada	32%	$1,850	$1,784	$1,733	$1,647	$47	$45	$62	$59
	Utah	30%	$1,793	$1,730	$1,680	$1,597	$46	$45	$62	$60
Wind	Arizona	29%	$1,824	$1,810	$1,797	$1,784	$58	$71	$79	$78
	Idaho	32%	$1,916	$1,901	$1,887	$1,873	$56	$68	$76	$76
	New Mexico (Existing Tx)	36%	$1,843	$1,830	$1,816	$1,803	$44	$56	$65	$64
	New Mexico	44%	$1,846	$1,832	$1,819	$1,805	$31	$44	$53	$53
	Pacific Northwest (Existing Tx)	30%	$2,188	$2,171	$2,155	$2,139	$69	$81	$89	$88
	Pacific Northwest	32%	$2,101	$2,085	$2,069	$2,054	$63	$75	$83	$82
	Southern Nevada	28%	$2,164	$2,148	$2,132	$2,116	$80	$91	$98	$98
	Utah	31%	$1,902	$1,888	$1,874	$1,860	$60	$72	$80	$80
	Wyoming	44%	$1,757	$1,744	$1,731	$1,718	$28	$41	$50	$50

For solar PV, the capital cost reductions shown in Table 20 reflect the default assumptions used in RESOLVE, but RESOLVE includes scenario settings for both low and high cost as alternatives. The three options for future capital cost reductions for solar PV are shown in Table 22.

Table 22. Alternative cost reduction trajectories for solar PV (% of 2016 capital cost).

RESOLVE Scenario Setting	2018	2022	2026	2030
Low	100%	100%	100%	100%
Mid	98%	94%	91%	87%
High	88%	77%	72%	68%

Beyond 2030, capital costs are assumed to remain constant in real terms.

4.2.3 TRANSMISSION COST & AVAILABILITY

Candidate renewable resources in RESOLVE may be selected for the portfolio either as **fully deliverable (FCDS)** resources or **energy only (EO)** resources, each representing a different classification of deliverability status by CAISO; the deliverability status assigned to each resource has implications for the transmission system as well as upon the value the resource provides to the system. The primary tradeoff between fully deliverable and energy only resources is the relative cost of transmission upgrades and the value of capacity provided by the resource: full deliverability allows a resource to count towards a utility's resource adequacy requirement but may require costly Deliverability Network Upgrades (DNUs); whereas energy only resources cannot be counted for capacity but do not require transmission upgrades for interconnection.

In each transmission zone, RESOLVE selects resources in three categories:

+ **FCDS resources on the existing system.** Each transmission zone is characterized by the amount of new capacity that can be installed on the existing system while still receiving full capacity deliverability status.
+ **EO resources on the existing system.** Each transmission zone is also characterized by the amount of incremental energy-only capacity that can be installed beyond the FCDS limits (i.e. this quantity is additive to the FCDS limit).
+ **FCDS resources on new transmission.** Resources in excess of the limits of the existing system may be installed but require investment in new transmission. This may occur (1) if both the FCDS

and EO limits are reached; or (2) if the FCDS limit is reached and the value of new capacity exceeds the cost of the new transmission investment.

Assumptions on the cost and availability of transmission for renewable resources are integrated from the RPS Calculator v.6.2, which, in turn, were provided by CAISO under a memorandum of understanding with the CPUC. Each transmission zone within the model is characterized by several assumptions, summarized in Table 23. Most of these input assumptions are provided by CAISO; where CAISO has not studied costs of transmission system upgrades, generic cost estimates from the RPS Calculator are used to supplement (indicated by * in the table).

Table 23. Transmission availability & cost in California

Transmission Zone	Existing Transmission, FCDS (MW)	Existing Transmission, EO (MW)	New Transmission Cost ($/kW-yr)
Central Valley North Los Banos	700	—	$28
Greater Carrizo	40	160	$89*
Greater Imperial	1,200	1,900	$60
Kramer Inyokern	1,000	1,000	$54
Mountain Pass El Dorado	800	2,200	$34
Northern California	668	4,232	$52*
Riverside East Palm Springs	2,950	2,550	$60
Solano	—	700	$13
Southern California Desert	—	—	$82*
Tehachapi	5,000	800	$13
Westlands	1,500	700	$11
Total	**13,858**	**14,242**	

New out-of-state resources are attributed an additional transmission cost, representing either the cost to wheel power across adjacent utilities' electric systems (for resources delivered on existing transmission) or the cost of developing a new transmission line (for resources delivered on new transmission). Wheeling costs on the existing system are derived from utilities' Open Access Transmission Tariffs; the cost of new transmission lines is based on assumptions developed for the CPUC's RPS Calculator v.6.2. These assumptions are shown in Table 24.

Table 24. Transmission cost assumptions for out-of-state resources

Zone	Existing Transmission Cost ($/kW-yr)	New Transmission Cost ($/kW-yr)
Arizona	—	$26
Idaho	—	$113
New Mexico	$72	$120
Northwest	$34	$86
Southern Nevada	—	$76
Utah	—	$60
Wyoming	—	$125

4.3 Energy Storage

In this section, the assumptions regarding costs and available potential (if applicable) regarding energy storage in RESOLVE are detailed.

Note that costs are broken down into power costs and energy costs. The power cost refers to all costs that scale with the rated installed power (kW) while the energy costs refers to all costs that scale with the duration/energy of the storage resource (kWh). For pumped storage, power costs are the largest fraction of total costs and relate to the costs of the turbines, the penstocks, the interconnection, etc., while energy costs are small and mainly cover the costs of digging a reservoir. For li-ion batteries, the power costs mainly relate to the cost of an inverter and other power electronics for the interconnection, while the energy costs relate to the actual Li-ion battery cells. For flow batteries, the power costs relate to the cost of an inverter and other power electronics, as well as the ion exchange membrane and fluids pumps, while the energy costs mainly relate to the tanks and the electrolyte. As a result, the power component of flow battery costs is higher than that of Li-ion, while the energy component is lower.

4.3.1 PUMPED STORAGE

The capital costs of candidate pumped storage resources, shown in Table 25 below, are based on *Lazard's Levelized Cost of Storage 2.0* (2016)[11]. Pumped storage costs are assumed to remain constant in real terms.

Table 25. Capital costs for candidate pumped storage resources

Cost Component	All Years
Capital Cost - Power ($/kW)	$1,307
Capital Cost - Energy ($/kWh)	$131
Fixed O&M Cost ($/kW-yr)	$24

These capital costs are fed into a pro forma model to estimate levelized fixed costs, using the following assumptions: financing lifetime of 25 years, fixed O&M of $24/kW-yr. with annual escalation of 2%, no variable O&M costs, and after-tax WACC of 7.71%. The resulting all-in levelized fixed costs are shown in Table 26 below.

Table 26. All-in levelized fixed costs ($/kW-yr and $/kWh-yr) for candidate pumped storage resources

Cost Component	All Years
Levelized Power Cost ($/kW)	$146
Levelized Energy Cost ($/kWh)	$12

The pumped storage resource potential assumptions are shown in Table 27 below.

Table 27. Available potential by year (MW) for candidate pumped storage resources.

Resource Class	2018	2022	2026	2030
Potential (MW)	—	2,000	4,000	4,000

[11] Available at: https://www.lazard.com/perspective/levelized-cost-of-storage-analysis-20/. E3 used the average of the range provided in p. 31 of the Appendix. For the breakout of power to energy cost, E3 used the specified duration (8-hours) and assumed energy costs per kWh are 1/10th of the power costs per kW.

4.3.2 BATTERY STORAGE

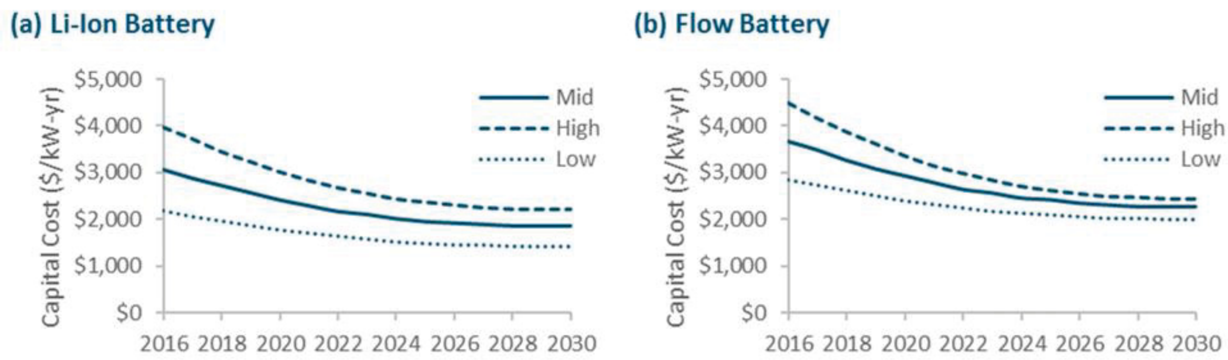
RESOLVE includes three options for candidate battery costs, each of which is based on *Lazard's Levelized Cost of Storage 2.0* (2016)[12]. The capital costs for each of these options - Mid, Low, and High – are shown in Table 28 below, along with fixed O&M costs expressed as a percentage of capital costs. Note that these include installation and interconnection costs.

Table 28. Capital cost assumptions for candidate battery resources.

Resource	Cost Component	Case	2018	2022	2026	2030
Li-Ion Battery	Capital Cost – Power ($/kW)	Low	$208	$172	$154	$150
		Mid	$248	$197	$172	$166
		High	$285	$218	$186	$179
	Capital Cost – Energy ($/kWh)	Low	$491	$406	$363	$352
		Mid	$689	$548	$479	$462
		High	$878	$672	$574	$550
	Fixed O&M (%)	All	1.0%	1.0%	1.0%	1.0%
Flow Battery	Capital Cost – Power ($/kW)	Low	$1,710	$1,470	$1,345	$1,313
		Mid	$2,120	$1,720	$1,521	$1,471
		High	$2,501	$1,913	$1,635	$1,567
	Capital Cost – Energy ($/kWh)	Low	$229	$197	$180	$176
		Mid	$292	$237	$210	$203
		High	$352	$269	$230	$220
	Fixed O&M (%)	All	2.5%	2.5%	2.5%	2.5%

[12] For flow batteries, the Peaker Replacement and Transmission cost tables in the Appendix are used, while for Li-ion the Frequency Regulation cost table was used. By using both the Peaker Replacement and Transmission cost table for flow batteries, E3 interpolated the membrane costs and other costs that scale with power but are not included in Lazard's AC costs. The Mid Case represents the average of Lazard's range, while the Low and High Case represent resp. the low end and the high end of the range. Cost trajectories are estimated based on Lazard's Capital Cost Outlook (p. 19). We assume that costs no longer go down after 2030 (in real terms).

Figure 8. Battery capital cost trajectories (4-hr duration)



These capital costs are then fed into a pro forma model to estimate levelized fixed costs, using the following assumptions: financing lifetime of 20 years and after-tax WACC of 7.58%. For Li-ion, we assumed replacement of the battery cells at year 10 at the projected cost of the energy component of the Li-battery in the year of replacement (e.g. the replacement cost of a Li-ion system built in 2020 would be the 2030 energy cost, which is $462/kWh in the Mid Case). The resulting all-in levelized fixed costs are shown in Table 29 below.

Table 29. All-in levelized fixed costs ($/kW-yr and $/kWh-yr) for candidate battery resources

Resource	Cost Component	Case	2018	2022	2026	2030
Li-Ion Battery	Levelized Fixed Cost – Power ($/kW-yr)	Low	$24	$20	$18	$17
		Mid	$29	$23	$21	$20
		High	$34	$27	$23	$22
	Levelized Fixed Cost – Energy ($/kWh-yr)	Low	$59	$50	$44	$43
		Mid	$91	$72	$64	$62
		High	$122	$95	$82	$79
Flow Battery	Levelized Fixed Cost – Power ($/kW-yr)	Low	$203	$175	$160	$155
		Mid	$251	$203	$180	$175
		High	$296	$228	$197	$186
	Levelized Fixed Cost – Energy ($/kWh-yr)	Low	$27	$23	$21	$21
		Mid	$35	$28	$25	$24
		High	$42	$32	$27	$26

The default RESOLVE assumptions do not limit the available potential for candidate battery storage resources.

4.4 Demand Response

4.4.1 CONVENTIONAL DEMAND RESPONSE

Assumptions on the cost, performance, and potential of candidate new conventional demand response resources are based on the "Shed" resource in Lawrence Berkeley National Laboratory's report for the CPUC: *2015 California Demand Response Potential Study: Final Report on Phase 2 Results* (2016)[13]. The resource potential supply curve is based on data outputs from LBNL's DRPATH model, with the scenario assumptions outlined below in Table 30.

Table 30. Scenario assumptions for DRPATH model used to generate supply curve data

Category	Assumption
Base year	2020
DR Availability Scenario	Medium
Weather	1 in 2 weather year
Energy Efficiency Scenario	midAAEE
Rate Scenario	Rate Mix 1—TOU and CPP (as defined by LBNL report)
Cost Framework	Gross

The resulting supply curve is shown below in Figure 9.

[13] Lawrence Berkeley National Laboratory, *2015 California Demand Response Potential Study: Final Report on Phase 2 Results.* 2016. Available at: http://www.cpuc.ca.gov/General.aspx?id=10622**http://www.cpuc.ca.gov/General.aspx?id=10622**

Figure 9. Conventional DR supply curve.

4.4.2 ADVANCED DEMAND RESPONSE

Assumptions on the cost, performance, and potential of candidate advanced demand response resources—also referred to as "flexible loads"—are based on the "Shift" resource in Lawrence Berkeley National Laboratory's report for the CPUC: *2015 California Demand Response Potential Study: Final Report on Phase 2 Results* (2016)[14]. The resource potential supply curve is based on data outputs from LBNL's DRPATH model, with the scenario assumptions outlined below in Table 31.

Table 31. Scenario assumptions for DRPATH model used to generate supply curve data

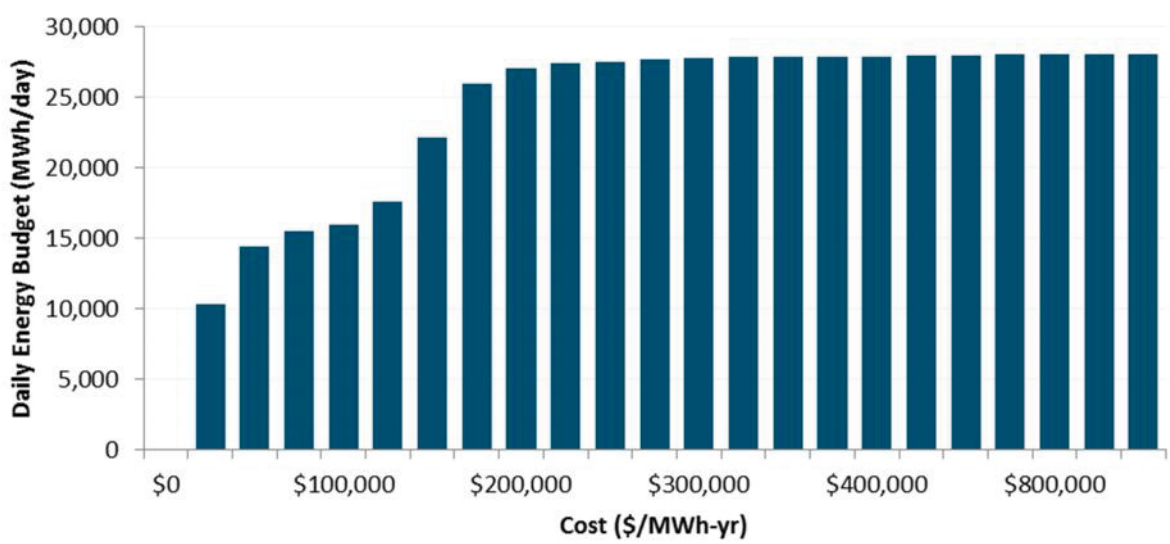
Category	Assumption
Base year	2020
DR Availability Scenario	Medium
Weather	1 in 2 weather year
Energy Efficiency Scenario	midAAEE

[14] Lawrence Berkeley National Laboratory, *2015 California Demand Response Potential Study: Final Report on Phase 2 Results.* 2016. Available at: http://www.cpuc.ca.gov/General.aspx?id=10622**http://www.cpuc.ca.gov/General.aspx?id=10622**

Rate Scenario	Rate Mix 1—TOU and CPP (as defined by LBNL report)
Cost Framework	Gross

The resulting supply curve is shown in Figure 10 below. Quantity of advanced demand response is reported in units of (MWh/day)-yr, which is the available *daily* energy budget for a given year. As this is based on the "Shift" resource, end-use energy consumption in the model can be shifted, for example, from on-peak hours to off-peak hours; the maximum amount of energy shifted in one day is the daily energy budget. RESOLVE includes an additional constraint that sets a maximum quantity of energy that can be shifted in one hour. A majority of this resource is based on weather-independent industrial process loads, so it is currently assumed that the full daily energy budget is available on every day of the year. It is also assumed that there is no efficiency loss penalty incurred by shifting loads to other times of the day.

Figure 10. Advanced demand response: total annual costs vs potential daily energy budget



5 Operating Assumptions

5.1 Overview

RESOLVE's objective function includes the annual cost to operate the electric system across RESOLVE's footprint; this cost is quantified using a linear production cost model.

+ **Zonal transmission topology:** RESOLVE uses a zonal transmission topology to simulate flows among the various regions in the Western Interconnection. RESOLVE includes six zones: four zones capturing California balancing authorities and two zones that represent regional aggregations of out-of-state balancing authorities. The constituent balancing authorities included in each RESOLVE zone are shown in Table 32.

Table 32. Constituent balancing authorities in each RESOLVE zone.

RESOLVE Zone	Balancing Authorities
BANC	Balancing Authority of Northern California (BANC) Turlock Irrigation District (TIDC)
CAISO	California Independent System Operator (CAISO)
LADWP	Los Angeles Department of Water and Power (LADWP)
IID	Imperial Irrigation District (IID)
NW	Avista Corporation (AVA) Bonneville Power Administration (BPA) Chelan County Public Utility District (CHPD) Douglas County Public Utility District (DOPD) Grant County Public Utility District (GCPD) Idaho Power Company (IPC) NorthWestern Energy (NWMT) Pacificorp East (PACE) Pacificorp West (PACW) Portland General Electric Company (PGE) Puget Sound Energy (PSE)

RESOLVE Zone	Balancing Authorities
	Seattle City Light (SCL) Sierra Pacific Power (SPP) Tacoma Power (TPWR) WAPA – Upper Wyoming (WAUW)
SW	Arizona Public Service Company (APS) El Paso Electric Company (EPE) Nevada Power Company (NEVP) Public Service Company of New Mexico (PNM) Salt River Project (SRP) Tucson Electric Power Company (TEP) WAPA – Lower Colorado (WALC)
Excluded	*Alberta Electric System Operator (AESO)* *British Columbia Hydro Authority (BCHA)* *Comision Federal de Electricidad (CFE)* *Public Service Company of Colorado (PSCO)* *WAPA – Colorado-Missouri (WACM)*

+ **Aggregated generation classes:** rather than modeling each generator within the study footprint independently, generators in each region are grouped together into categories with other plants whose operational characteristics are similar (e.g. nuclear, coal, gas CCGT, gas CT). Grouping like plants together for the purpose of simulation reduces the computational complexity of the problem without significantly impacting the underlying economics of power system operations.
+ **Linearized unit commitment:** RESOLVE includes a linear version of a traditional production simulation model. In RESOLVE's implementation, this means that the commitment variable for each class of generators is a continuous variable rather than an integer variable. Additional constraints on operations (e.g. Pmin, Pmax, ramp rate limits, minimum up & down time) further limit the flexibility of each class' operations.
+ **Co-optimization of energy & ancillary services:** RESOLVE dispatches generation to meet load across the Western Interconnection while simultaneous reserving flexible capacity within CAISO to meet the contingency and flexibility reserve needs of the CAISO balancing authority.
+ **Smart sampling of days:** whereas production cost models are commonly used to simulate an entire calendar year (or multiple years) of operations, RESOLVE simulates the operations of the WECC system for 37 independent days. Load, wind, and solar profiles for these 37 days, sampled

from the historical meteorological record of the period 2007-2009, are selected and assigned weights so that taken in aggregate, they produce a reasonable representation of complete distributions of potential conditions; daily hydro conditions are sampled separately from low (2008), medium (2009), and high (2011) hydro years to provide a complete distribution of potential hydro conditions.[15] This allows RESOLVE to approximate annual operating costs and dynamics while simulating operations for only the 37 days. The 37 days sampled are summarized in Table 33.

Table 33. RESOLVE's 37 days and associated weights.

Index	Weather Date	Hydro Condition	Day Weight	Index	Weather Date	Hydro Date	Day Weight
1	1/1/07	High	14.250	20	5/7/08	High	5.808
2	1/2/07	Mid	5.908	21	5/19/08	Low	15.361
3	2/12/07	High	28.022	22	6/2/08	Low	17.733
4	3/6/07	High	14.341	23	8/3/08	Mid	20.807
5	3/20/07	Low	6.699	24	10/28/08	Low	1.167
6	4/2/07	High	0.495	25	11/5/08	Mid	12.447
7	4/8/07	Low	2.197	26	12/20/08	High	33.401
8	4/15/07	Low	1.133	27	1/6/09	Mid	0.881
9	5/5/07	Mid	5.384	28	1/21/09	Mid	7.922
10	5/29/07	High	3.902	29	3/26/09	High	8.913
11	6/2/07	High	9.228	30	4/4/09	Low	3.381
12	6/16/07	High	1.631	31	4/17/09	High	9.045
13	7/17/07	Mid	31.789	32	4/24/09	High	5.718
14	8/7/07	High	4.542	33	4/25/09	Low	4.810
15	9/2/07	High	13.817	34	4/25/09	High	0.903
16	9/26/07	Low	16.348	35	6/24/09	High	1.748
17	11/27/07	High	19.042	36	8/17/09	Low	5.811
18	1/28/08	Mid	0.664	37	10/6/09	High	28.928

[15] An optimization algorithm is used to select the days and identify the weight for each day such that distributions of load, net load, wind, and solar generation match long-run distributions.

Index	Weather Date	Hydro Condition	Day Weight	Index	Weather Date	Hydro Date	Day Weight
19	4/4/08	High	0.822	**Total**			**365.000**

5.2 Load & Renewable Profiles

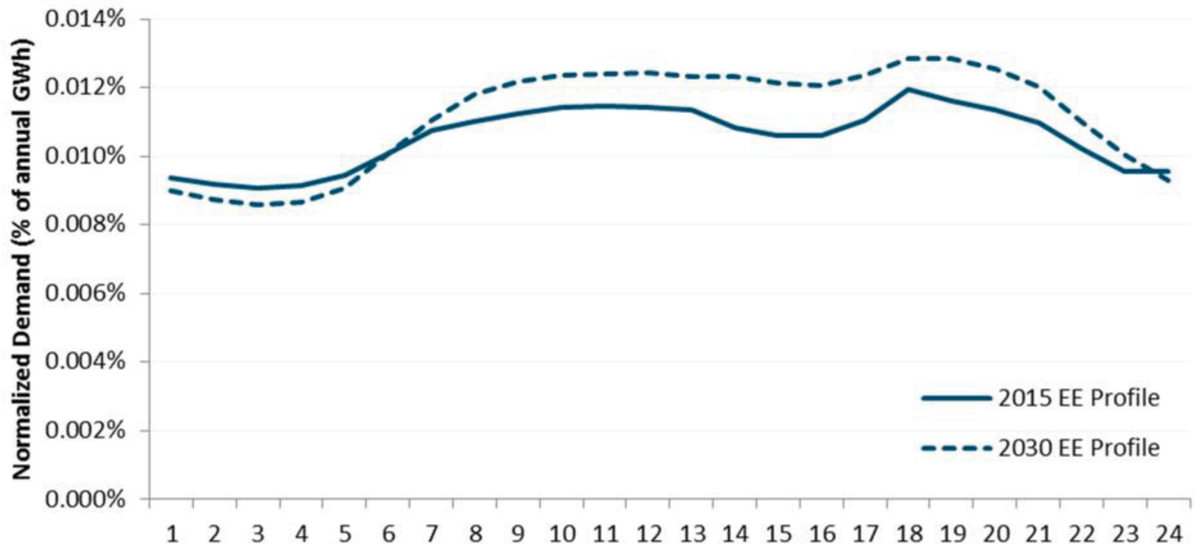
5.2.1 LOAD PROFILES

Load profiles are based on historical loads for the zones of interest as reported by the Western Electricity Coordinating Council (WECC) for 2007-2009. Since there were virtually no behind-the-meter PV, electric vehicles, additional energy efficiency, or time-of-use rate impacts at that time, these profiles are assumed to reflect the baseline profile. For the non-CAISO zones, these profiles are used "as is", whereas for the CAISO zone, the final load profile is obtained by adding appropriate shapes for behind-the-meter PV, electric vehicles, energy efficiency, and time-of-use rate impacts to the baseline profile. The baseline profiles and the adjustments can be found in the LOADS_profiles worksheet of the User Interface spreadsheet.

5.2.1.1 Energy Efficiency Profiles

The EE profiles used by RESOLVE for 2015 and 2030 are shown Figure 11 below. As can be seen, the profiles roughly follow the load profile. For years in between 2015 and 2030, a linear interpolation of both profiles is used. For years beyond 2030, the 2030 profile is used. These profiles are based on the hourly profiles developed by the CEC to represent the load impact of Additional Achievable Energy Efficiency in the 2015 IEPR Demand Forecast.

Figure 11. Energy efficiency profile (January representative day)



5.2.1.2 Electric Vehicle Load Profiles

EV load profiles are created using an EV charging model developed by E3. The charging model is based on the 2009 National Household Transportation Survey ("NHTS"), a dataset on personal travel behavior[16]. The model translates travel behavior into aggregate EV load shapes by weekday/weekend-day, charging strategy, and charging location availability. The weekend/weekday shapes are aggregated and normalized into month-hour shapes by charging location availability. A blend is created by assuming a certain fraction of drivers have charging infrastructure available both at home and their workplace, while the rest of the drivers only have charging infrastructure available at home. There are three predefined settings available for the fraction of drivers that have workplace charging available, as shown in Table 34 below.

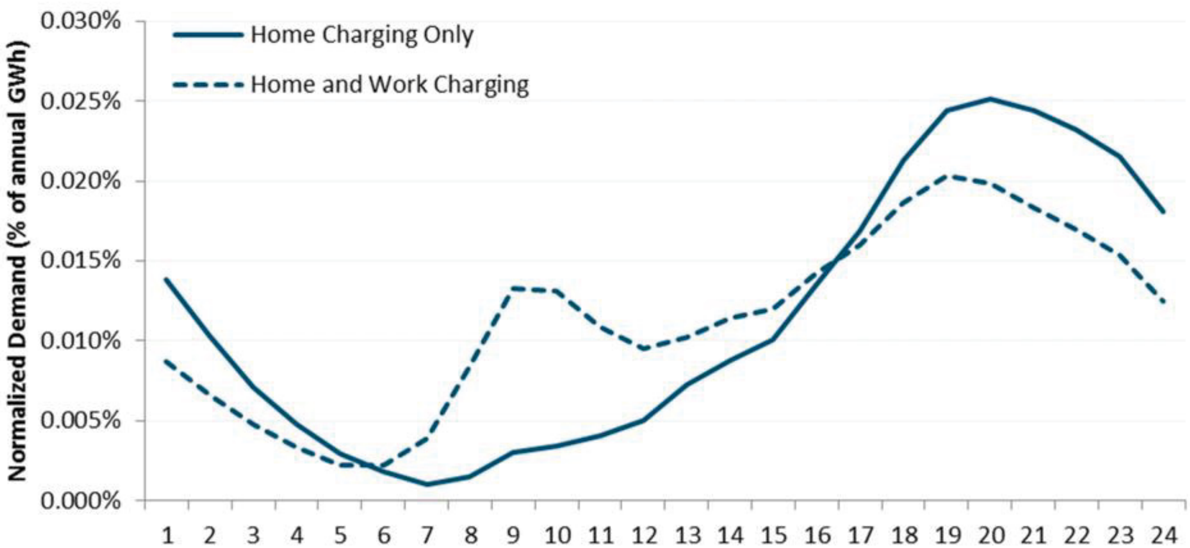
Table 34. Workplace charger availability by scenario.

Scenario Setting	2018	2022	2026	2030

[16] Available at: http://nhts.ornl.gov/introduction.shtml

Low	2%	5%	7%	10%
Mid	6%	14%	22%	30%
High	16%	37%	59%	80%

Figure 12. Electric vehicle charging shape for January by charger availability.



RESOLVE also has the option to have flexible EV charging, which lets the RESOLVE model dynamically optimize the charging shape. There are three predefined settings available for the fraction of EV load that is flexible, as shown in Table 35 below. Note that the default assumption is to have no flexible EV charging ("Low" scenario).

Table 35. Fraction of flexible electric vehicle charging by scenario.

Scenario Setting	2018	2022	2026	2030
Low	0%	0%	0%	0%
Mid	4%	9%	15%	20%
High	10%	23%	37%	50%

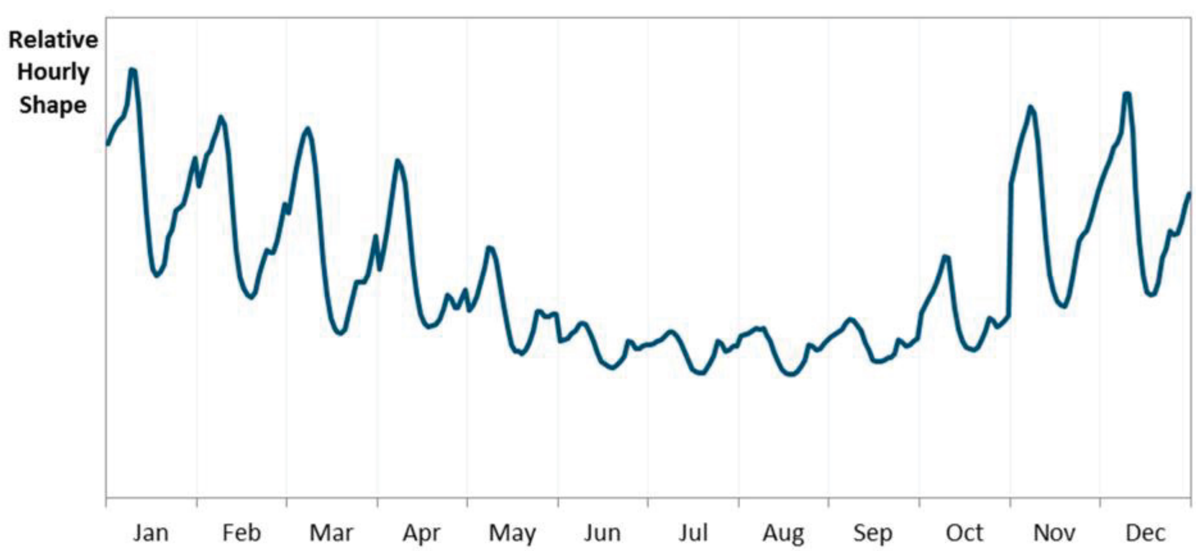
For the vehicles that have flexible charging, the optimal charging shape is constrained by the amount of vehicles that is plugged in, which defines how much charge capacity is available, and the instantaneous driving demand for that hour, which affects the state-of-charge of the fleet.

5.2.1.3 Building Electrification Profiles

The load profiles used to represent incremental building electrification are based on the end-use load shapes used in E3's PATHWAYS model, used in the development of CARB's Scoping Plan. The profile included in RESOLVE is a composite of shapes associated with the following end uses: (1) residential cooking, (2) residential space heating, (3) residential water heating, (4) commercial space heating, and (5) commercial water heating. In the composite shape for building electrification, each of these end uses is weighted in proportion to the relative amount of incremental electrification observed by 2030 in CARB's Alternative 1 scenario.

Within RESOLVE, the shape for building electrification is input as a representative hourly shape for each month. The representative hourly shape for each month is shown in Figure 13. As illustrated in this figure, building electrification loads are more concentrated in the winter due to the electrification of space heating and water heating end uses.

Figure 13. Building electrification load shape by month



5.2.1.4 Time-of-Use Rates Adjustment Profiles

Time-of-use rate profile impacts are based on a 2015 study by Christensen Associates (2015)[17]. E3 applied the 2025 TOU load impacts from this study to the relevant periods of the 37 modeled days (summer peak, summer off-peak, winter peak, etc.) to obtain the TOU shape for 2025. For all other years, the TOU adjustment was scaled based on the ratio of the load (net of EE) of that year vs. the load in 2025. The 2025 profile and the scalars for each year can be found in the LOADS_profiles worksheet of the User Interface spreadsheet. As can be seen, the TOU adjustments are relatively small, maxing out at a reduction of about 150 MW for the year 2025.

5.2.2 SOLAR PV PROFILES

Solar profiles for RESOLVE are created using a python-based solar simulation tool made by E3. The tool uses standard solar modeling principles as laid out by Sandia's PV Performance Modeling Collaborative[18] to simulate PV production based on weather data from the National Solar Radiation Database (NSRDB).[19]

For each of the resources modeled in RESOLVE, NSRDB data for five to twenty representative lat-lon coordinates (more for larger regions) is collected for the years 2007-2009. PV production profiles for each of these locations are then simulated for a fixed-tilt configuration, a single-axis tracking configuration, and a behind-the-meter rooftop configuration. The inverter loading ratio is assumed to be 1.3 for utility-scale systems, and 1.1 for behind-the-meter systems. Next, aggregate profiles for each resource and configuration (fixed-tilt, single-axis tracking, behind-the-meter) are obtained by taking the average of the representative locations. For utility scale resources (everything but behind-the-meter PV), one last step involves aggregating the utility scale profiles, assuming 25% is fixed tilt and 75% is tracking.

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[17] *Statewide Time-of-Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report.* Available at: **http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207031_20151215T151300_Statewide_TimeofUse_Scenario_Modeling_for_2015_California_Energ.pdf**

[18] Available at: **https://pvpmc.sandia.gov/** The modeling framework and assumptions on this website are very similar to what is used in NREL's PVWatts tool and NREL's System Advisor Model.

[19] See: **https://nsrdb.nrel.gov/current-version**

Before the solar profiles can be used in RESOLVE, they are scaled such that the weighted capacity factor of the 37 modeled days matches the capacity factor derived from the CPUC's RPS Calculator (Version 6.2) Supply Curve. For out-of-state resources, the target capacity factors are based on data from the 2026 WECC Common Case. The reshaping is done by linearly scaling the shape up or down until the target capacity factor is met. When scaling up, the maximum normalized output is capped to 100% to ensure that a profile's hourly production does not exceed its rated installed capacity. This essentially mimics increasing/decreasing the inverter loading ratio.

The final capacity factors are shown in Table 36 below. The final shapes can be found in the REN_Profiles worksheet.

Table 36. Solar capacity factors in RESOLVE (%)

Category	Resource	Capacity Factor
Baseline Resources	CAISO_Solar_for_CAISO	30%
	CAISO_Solar_for_Other	28%
	IID_Solar_for_CAISO	29%
	NW_Solar_for_Other	24%
	SW_Solar_for_CAISO	32%
	SW_Solar_for_Other	27%
	Customer_PV*	19%
Candidate Resources	Northern_California_Solar	30%
	Solano_Solar	29%
	Central_Valley_North_Los_Banos_Solar	30%
	Westlands_Solar	30%
	Greater_Carrizo_Solar	32%
	Tehachapi_Solar	35%
	Kramer_Inyokern_Solar	36%
	Mountain_Pass_El_Dorado_Solar	35%
	Southern_California_Desert_Solar	35%
	Riverside_East_Palm_Springs_Solar	34%
	Greater_Imperial_Solar	34%
	Distributed_Solar	23%
	Baja_California_Solar	35%
	Utah_Solar	30%
	Southern_Nevada_Northwest_Arizona_Solar	32%

	Arizona_Solar	34%
	New_Mexico_Solar	33%

** Customer_PV profile represents all behind-the-meter solar PV installations*

5.2.3 WIND PROFILES

Hourly shapes for wind resources are obtained from NREL's Wind Integration National Dataset ("WIND") Toolkit.[20] For each of the wind resources modeled in RESOLVE, wind production profiles for a set of representative locations is collected for the years 2007-2009. The profiles are then adjusted using a filter such that such that the weighted capacity factor of the 37 modeled days matches the capacity factor derived from the CPUC's RPS Calculator v.6.3 supply curve. For out-of-state resources, the target capacity factors are based on data from the 2026 WECC Common Case. The filter is set up such that outputs at lower level are affected more (to represent better/worse turbine technology), while hourly ramps are preserved.

The final capacity factors are shown in Table 37 below. The final shapes can be found in the REN_Profiles worksheet.

Table 37. Wind capacity factors in RESOLVE (%)

Category	Resource	Capacity Factor
Baseline Resources	Contracted_NW_Wind	32%
	CAISO_Wind_for_CAISO	28%
	CAISO_Wind_for_Other	28%
	SW_Wind_for_CAISO	44%
	NW_Wind_for_Other	29%
	SW_Wind_for_Other	44%
Candidate Resources	Northern_California_Wind	29%
	Solano_Wind	30%
	Central_Valley_North_Los_Banos_Wind	31%
	Greater_Carrizo_Wind	31%
	Tehachapi_Wind	33%

[20] See: **https://www.nrel.gov/grid/wind-toolkit.html**

Category	Resource	Capacity Factor
	Kramer_Inyokern_Wind	32%
	Southern_California_Desert_Wind	27%
	Riverside_East_Palm_Springs_Wind	33%
	Greater_Imperial_Wind	31%
	Distributed_Wind	28%
	Baja_California_Wind	36%
	Pacific_Northwest_Wind	32%
	Idaho_Wind	32%
	Utah_Wind	31%
	Wyoming_Wind	44%
	Southern_Nevada_Northwest_Arizona_Wind	28%
	Arizona_Wind	29%
	New_Mexico_Wind	44%

5.3 Operating Characteristics

5.3.1 CONVENTIONAL

As discussed in Sections 3.1, the thermal fleet in RESOLVE is represented by a limited set of resource classes by zone that represent the capacity-weighted average for each resource class in that zone. The operating characteristics (Pmax, Pmin, heat rate etc.) for each resource class are compiled from the 2026 TEPPC Common Case. For the CAISO zone, these operating characteristics are matched with the NQC list and shown explicitly in the CAISO_Gen_List worksheet, after which they are aggregated by resource class in the CONV_OpChar worksheet. For all other zones, the aggregation is done as separate pre-processing step, and only the final, aggregated results are shown. Operating parameters for each resource class are based on a capacity-weighted average of individual plant operating characteristics, most of which are gathered from the TEPPC 2026 Common Case. Several plant types are modeled using operational information from other sources:

+ The CAISO_Aero_CT and CAISO_Advanced_CCGT operating characteristics are based on manufacturer specifications of the latest available models of these class.

+ The CAISO_CHP plant type is modeled as a must-run resource at its full NQC capacity with an assumed net heat rate of 7,600 Btu/kWh, based on CARB's Scoping Plan assumptions for cogeneration.

The operating characteristics for each of the generator classes in RESOLVE are shown below in Table 38.

Table 38. Main operating characteristics of the conventional generator fleet in RESOLVE

Resource	Zone	Must Run	Pmax (MW)	Pmin (MW)	Max Ramp Rate (%Pmax/hr)	Heat Rate at Pmax (Btu/MWh)	Heat Rate at Pmin (Btu/MWh)	Min Up/Down Time (hrs)	Startup Cost ($/MW)
CAISO_CHP	CAISO	TRUE	20	20	0%	7.606	7.606	24	$62
CAISO_Nuclear	CAISO	TRUE	584	423	18%	12.554	13.008	24	$113
CAISO_CCGT1	CAISO		484	291	64%	6.865	7.280	6	$93
CAISO_CCGT2	CAISO		248	129	54%	7.381	7.996	6	$85
CAISO_Peaker1	CAISO		62	29	378%	9.308	12.904	1	$86
CAISO_Peaker2	CAISO		46	22	338%	12.110	15.182	1	$49
CAISO_Advanced_CCGT	CAISO		600	120	100%	6.833	10.167	1	$50
CAISO_Aero_CT	CAISO		100	30	100%	9.572	17.632	—	$10
CAISO_Reciprocating_Engine	CAISO		5	1	1495%	9.151	10.893	—	$7
CAISO_ST	CAISO		337	27	102%	9.663	17.117	6	$78
CAISO_CCGT_Retrofit	CAISO		484	97	64%	6.865	7.280	2	$93
Conventional_DR	CAISO		1	0	100%			—	—
NW_Nuclear	NW	TRUE	1,170	1,170	20%	10.907	10.907	24	—
NW_Coal	NW		305	129	66%	10.609	11.259	24	$16
NW_CCGT	NW		337	178	57%	7.141	7.721	6	$15
NW_Peaker	NW		28	10	322%	10.591	12.500	1	$714
SW_Nuclear	SW	TRUE	1,403	1,403	19%	10.544	10.544	24	—
SW_Coal	SW		414	174	57%	10.374	11.211	24	$12
SW_CCGT	SW		372	205	55%	7.143	7.667	6	13
SW_Peaker	SW		71	26	249%	10.554	14.269	1	$282
LDWP_Nuclear	LDWP	TRUE	152	152	19%	10.544	10.544	24	—
LDWP_Coal	LDWP		900	328	54%	9.608	10.289	24	$6
LDWP_CCGT	LDWP		215	123	110%	6.995	7.095	6	$23
LDWP_Peaker	LDWP		74	36	201%	9.042	10.532	1	$272
IID_CCGT	IID		128	61	72%	7.905	9.209	6	$85
IID_Peaker	IID		41	14	429%	12.140	16.208	1	$49
BANC_CCGT	BANC		234	124	75%	7.677	8.037	6	$85
BANC_Peaker	BANC		40	16	292%	10.392	12.121	1	$49

For must-run generators, the assumptions regarding availability by month are shown in Table 39 below.

Table 39. Monthly availability by generator type (% of nameplate)

Resource	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NW_Nuclear	100%	100%	100%	100%	50%	50%	100%	100%	100%	100%	100%	100%
SW_Nuclear	100%	100%	100%	75%	75%	100%	100%	100%	75%	75%	100%	100%
LDWP_Nuclear	100%	100%	100%	75%	75%	100%	100%	100%	75%	75%	100%	100%
CAISO_Nuclear	100%	100%	100%	75%	75%	100%	100%	100%	75%	75%	100%	100%
NW_Coal	95%	95%	95%	95%	50%	50%	95%	95%	95%	95%	95%	95%
SW_Coal	95%	95%	95%	50%	50%	95%	95%	95%	95%	95%	95%	95%
LDWP_Coal	95%	95%	95%	50%	50%	95%	95%	95%	95%	95%	95%	95%

Monthly derates for each plant reflect assumptions regarding the timing of annual maintenance requirements. Nuclear maintenance and refueling is assumed to be split between the spring (April & May) and the fall (September & October) so that the plants can be available to meet summer and winter peaks. Annual maintenance of the coal fleets in the WECC is assumed to occur during the spring months, when wholesale market economics tend to suppress coal capacity factors due to high hydro availability and low loads.

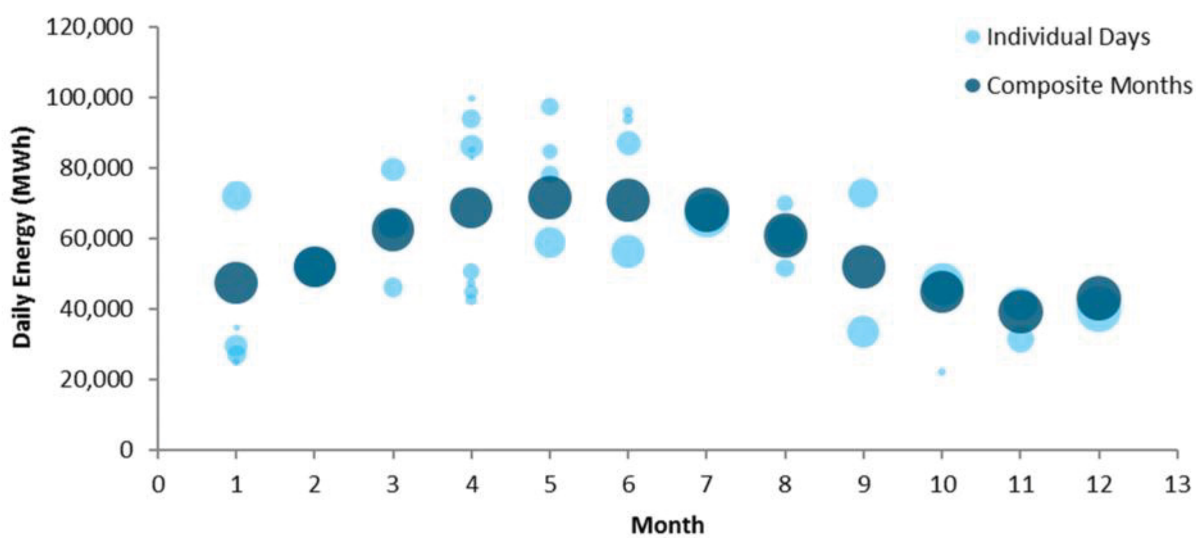
5.3.2 HYDRO

The operations of the hydro fleets in each region are constrained on each day by three constraints:

+ **Daily energy budget:** the total amount of energy, in MWh, to be dispatched throughout the day; and
+ **Daily maximum and maximum output:** upper and lower limits, in MW, for power production intended to capture limits on the flexibility of the regional hydro system due to hydrological, biological, and other technical factors; and
+ **Ramping capability:** within CAISO, the ramping capability of the fleet it further constrained by hourly and multi-hour ramp limitations (up to four hours), which are derived from historical CAISO hydro operations.

In the CAISO, these constraints are drawn from the actual historical record: the daily budget and minimum/maximum output are based on actual CAISO operations on the day of the year from the appropriate hydrological year (low = 2008, mid = 2009, high = 2011) that matches the canonical day used for load, wind, and solar conditions (e.g., as presented in Table 33, day 3 uses February 12, 2007 for load, wind, and solar conditions and uses 2011 hydro conditions; therefore, the daily budget and operational range is based on actual CAISO daily operations on February 12, 2011). Figure 14 summarizes the daily energy budgets for each of the 37 days modeled in RESOLVE.

Figure 14. Daily energy budgets for CAISO hydro fleet



In the chart above, each of the 37 days is shown as a light blue point according to its calendar month. The size of the bubble in the diagram above represents the weight assigned to that day in RESOLVE. The dark blue points represent the average hydro budget for all days in that month.

Outside CAISO, where daily operational data was not available, assumed daily energy budgets are derived from monthly historical hydro generation as reported in EIA Form 906/923 (e.g., in the example discussed above for Day 3, the daily energy budgets for other regions is based on average conditions in February 2011). Minimum and maximum output for regions outside CAISO are based on functional relationships between daily energy budgets and the observed operable range of the hydro fleet derived from historical data gathered from WECC.

5.3.3 ENERGY STORAGE

The efficiency and minimum duration for each of the storage technologies modeled in RESOLVE is shown in Table 40 below.

Table 40. Assumptions for new energy storage resources

Technology	Round-Trip Efficiency	Minimum Duration (hours)
Li_Battery	85%	1
Flow_Battery	70%	1
Pumped_Hydro	81%	12

For all storage devices, we assume that they have no minimum generation or minimum "discharging" constraint, allowing them to charge or discharge over a continuous range. For pumped storage, this is a simplification, as pumps and generators typically have a somewhat limited operating range. We also don't specify ramp rates for storage devices, implicitly assuming that they can ramp over their full operable range almost instantly.

5.4 Reserve Requirements

RESOLVE models the following reserve products for the CAISO main zone:

Table 41. Reserve types modeled in RESOLVE

Product	Description	RESOLVE Requirement	Operating Limits
Frequency Response	Aside from system inertia, this is the fastest reserve type and is operated through governor response. In RESOLVE, it is assumed that storage devices can provide these services as well.	The default assumption in RESOLVE is to hold 770 MW, of which half is held by non-modeled resources, which results in a remaining requirement of 385 MW.	For thermal generators, we assume that they can contribute 8% of their committed capacity. For storage devices, we assume that they can provide all their available headroom.
Regulation Up/Down	This is the second fastest reserve product modeled (5 min – 4 sec). This reserve	The default assumption is 1% of the hourly CAISO load both for regulation up and	We assume that thermal generators can provide all their available

Product	Description	RESOLVE Requirement	Operating Limits
	product ensures that the system's frequency, which can deviate due to real-time swings in the load/generation balance, stays within a defined band. In practice, this is controlled by generators on Automated Generator Control (AGC), which get sent a signal based on the frequency deviations of the system.	regulation down.	headroom/footroom[21], limited by their 10-min ramp rate. Storage systems are only constrained by their available headroom/footroom. Storage systems.
Load Following Up/Down	This reserve product ensures that sub-hourly variations from the load forecast, as well as lumpy blocks of imports/exports/generator commitments, are dealt with by the system in real-time.	RESOLVE uses an hourly requirement based on subhourly analysis that was done for one 33% and two 50% RPS cases in the CAISO system. This analysis parameterized the hourly load following requirements for each of the 37 RESOLVE model days based on the renewable penetration and diversity (high solar vs. diverse).	We assume that thermal generators can provide all their available headroom/footroom, limited by their 10-min ramp rate. Storage systems are only constrained by their available headroom/footroom.
Spinning Reserve	This contingency reserve ensures that there are enough generators online in case of an outage or other contingency. We assume a CAISO spinning reserve requirement of 3% of the hourly load.	The default assumption is 3% of the hourly CAISO load both for regulation up and regulation down.	We assume that thermal generators can provide all their available headroom/footroom, limited by their 10-min ramp rate. Storage systems are only constrained by their available headroom/footroom. RESOLVE ensures that storage has enough state-of-charge available to provide spinning reserves, but deployment (which would reduce the state-of-charge) is not explicitly modeled.

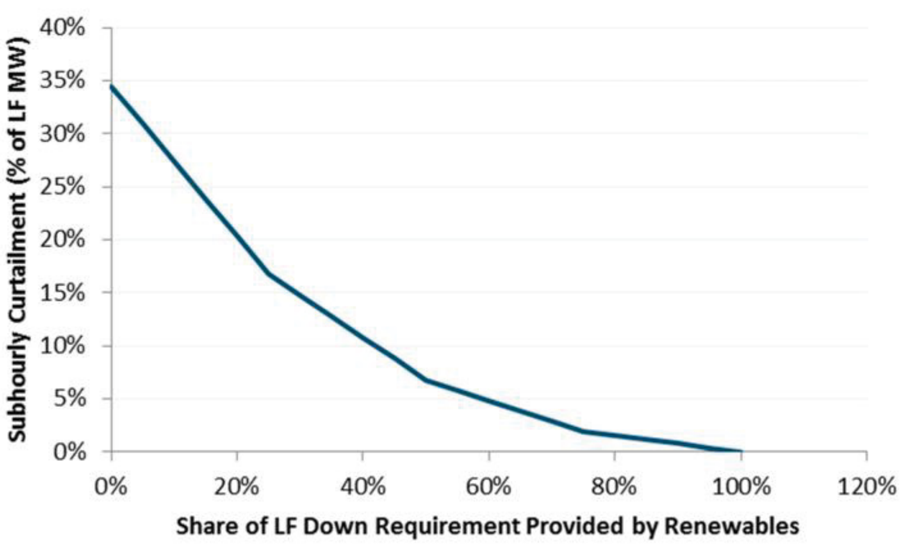
[21] For generators, headroom and footroom are defined as the difference between the current operating level and the maximum and minimum generation output, respectively. For storage devices, headroom and footroom are defined as the difference between the current operating level and resp. the maximum discharge capacity, and maximum charge capacity, e.g. a 100 MW battery charging at 50 MW has a headroom of 150 MW (100 – (-50)) and a footroom of 50 MW.

Non-spinning reserves are not modeled in RESOLVE. Also, reserves are not modeled in any of the non-CAISO zones.

Deployment of reserves is only modeled for storage devices, and only for regulation and load following (not for spinning reserve and primary frequency response). The default assumption for deployment for these services is 20%. In other words, for every MW of regulation or load following up provided in a certain hour, we assume that the storage device is discharged 0.2 MWh (and vice versa for regulation / load following down).

In the base case, we assume that renewables can provide load following down, but only up to 50% of the load following down requirement. This allows renewables to be curtailed on the subhourly level to provide reserves. The amount of subhourly curtailment (i.e. the deployment) is parametrized by a "Reflex Surface" in the SYS_Reserves worksheet. Figure 15 shows the amount of subhourly curtailment this results in. For instance, when all load following down is met by renewables, this surface indicates that the amount of subhourly curtailment that would occur would be equal to 34% of the hourly downward load following requirement across the hour (i.e. "deployed"). Note that for storage devices providing load following down (or up), we assume a flat 20% deployment.

Figure 15. Anticipated subhourly renewable curtailment as a function of load following met by renewables.



5.5 Transmission Topology

The zonal transmission topology assumed in RESOLVE is shown in Figure 16. This topology is based on compiled information from a number of public data sources. Where possible, transfer capability between zones is tied to rated WECC paths, per the WECC 2016 Path Catalog In instances where rating in one direction (e.g., West-to-East) is not defined, it is assumed to be symmetric with the opposite direction. WECC path ratings are complemented by other available data, including scheduling total transfer capacity provided on the OASIS sites of certain utilities and transmission owners. Where path data is not available, the sum of thermal ratings on lines connecting neighboring zones in WECC's nodal TEPPC cases has been used to allocate or provide information. This data is supplemented by other documents identified in past public filings online, as well as conversations with transmission engineers, to approximate actual operations to the extent possible.

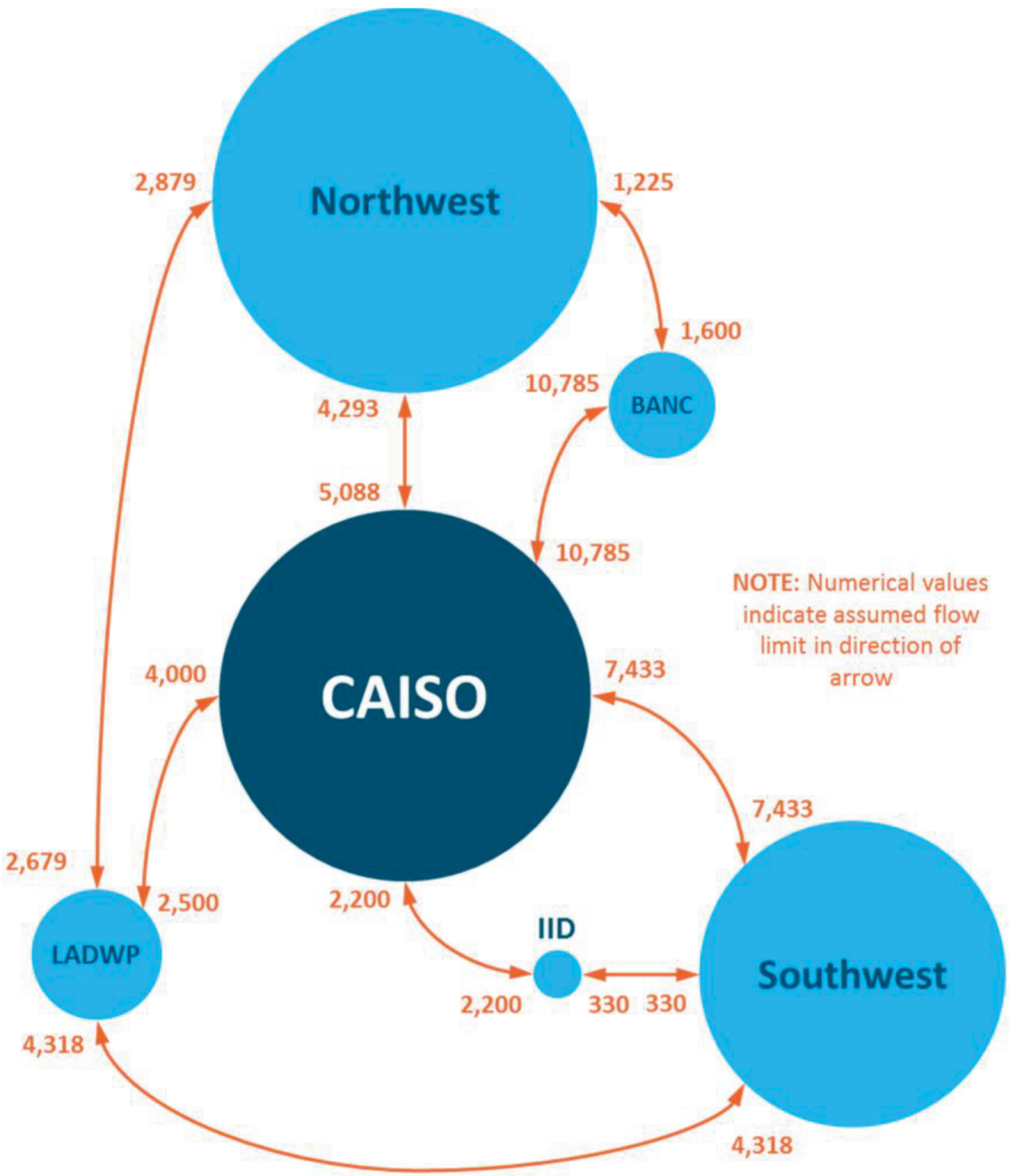
RESOLVE also incorporates hurdle rates for transfers between zones; these hurdle rates are intended to capture the transactional friction to trade energy across neighboring transmission systems. The hurdle rates, shown in Table 42, are based on CAISO's 2014 LTPP PLEXOS Case, and are tied to the zone of export (e.g., sending power from CAISO to the NW, or any other zone, incurs a hurdle rate of \$9.96/MWh).

Table 42. Hurdle rates in RESOLVE ($/MWh)

Export Zone	Hurdle Rate ($/MWh)
From BANC	$2.47
From CAISO	$9.96
From IID	$4.07
From LDWP	$5.71
From NW	$3.89
From SW	$3.86

In addition to these cost-based hurdle rates, an additional cost is attributed to all imports to California reflecting the cost to import unspecified power into California under CARB's cap and trade program; this cost is calculated based on the relevant year's carbon cost (see Table 47) and a deemed rate of 0.43 tons/MWh.

Figure 16. Transmission topology used in RESOLVE (transfer limits shown in MW).



In addition to the physical underlying transmission topology shown above, RESOLVE also includes a constraint on the simultaneous net exports from CAISO. This constraint is included to capture explicitly the uncertainty in the size of the future potential market for California's exports of surplus renewable power. RESOLVE includes three options for the export constraint from California, shown in Table 43.

Table 43. Assumed CAISO net export limits (MW)

Scenario Setting	2018	2022	2026	2030
Low	2,000	2,000	2,000	2,000
Mid	2,000	3,000	4,000	5,000
High	2,000	4,000	6,000	8,000

5.6 Fuel Costs

RESOLVE includes three options for fuel costs, each of which is based on a WECC burner tip price estimate using CEC's 2015 IEPR Demand Forecast[22]. Prices for each region were calculated using the average of the region of interest, and were adjusted for inflation (2%/yr.) to reflect 2016 dollars. These forecasts – Low, Mid, High – are shown in Table 44, Table 45, and Table 46.

Table 44. Fuel Cost Forecast – Low ($/MMBtu, 2016$).

Fuel Type	2018	2022	2026	2030
CA_Natural_Gas	$3.86	$4.21	$4.57	*$4.39*
NW_Natural_Gas	$3.28	$3.54	$3.87	*$3.76*
SW_Natural_Gas	$3.57	$3.85	$4.18	*$4.02*
CA_Coal	$2.00	$2.00	$2.00	*$2.00*
Coal	$2.00	$2.00	$2.00	*$2.00*
Uranium	$0.70	$0.70	$0.70	*$0.70*

Values shown in italics are extrapolated based on the average linear growth rate between 2021 and 2026.

[22] Available here: http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN209537_20160126T084035_WECC_Gas_Hub_Burner_Tip_Price_Estimates_using_2015_IEPR_Natural.xlsx

Table 45. Fuel Cost Forecast – Mid ($/MMBtu, 2016$).

Fuel Type	2018	2022	2026	2030
CA_Natural_Gas	$4.50	$5.24	$5.50	*$5.33*
NW_Natural_Gas	$3.92	$4.57	$4.80	*$4.70*
SW_Natural_Gas	$4.21	$4.88	$5.11	*$4.96*
CA_Coal	$2.00	$2.00	$2.00	*$2.00*
Coal	$2.00	$2.00	$2.00	*$2.00*
Uranium	$0.70	$0.70	$0.70	*$0.70*

Values shown in italics are extrapolated based on the average linear growth rate between 2021 and 2026.

Table 46. Fuel Cost Forecast – High ($/MMBtu, 2016$).

Fuel Type	2018	2022	2026	2030
CA_Natural_Gas	$5.70	$6.59	$7.17	*$7.06*
NW_Natural_Gas	$5.12	$5.93	$6.46	*$6.42*
SW_Natural_Gas	$5.41	$6.23	$6.77	*$6.68*
CA_Coal	$2.00	$2.00	$2.00	*$2.00*
Coal	$2.00	$2.00	$2.00	*$2.00*
Uranium	$0.70	$0.70	$0.70	*$0.70*

Values shown in italics are extrapolated based on the average linear growth rate between 2021 and 2026.

RESOLVE includes four options for carbon costs, each of which is based on the preliminary 2015 IEPR Nominal Carbon Price Projections. This forecast projects a 5% year-over-year increase of the carbon price, plus annual inflation. Nominal prices were brought back to 2016 dollars assuming a constant 2% inflation rate. These forecasts – Low, Mid, High, Zero – are shown in Table 47. The model's default assumption is to only apply these carbon prices to resources in California, as well as generation imported to California.

Table 47. Carbon Cost Forecast Options ($/tCO2, 2016$).

Fuel Type	2018	2022	2026	2030
Low	$ 15.17	$ 18.86	$ 23.44	$ 29.28
Mid	$ 15.17	$ 28.29	$ 35.16	$ 43.92

High	$ 45.52	$ 56.59	$ 70.31	$ 87.83
Zero	—	—	—	—

Values shown in italics are extrapolated based on the average linear growth rate between 2026 and 2030.

6 Resource Adequacy Requirements

6.1 System Resource Adequacy

To ensure that the optimized generation fleet is sufficient to meet resource adequacy needs throughout the year, RESOLVE includes a planning reserve margin constraint that requires the total available generation plus available imports in each year to meet or exceed a 15% margin above the annual 1-in-2 peak demand. The contribution of each type of generation resource to this requirement depends on its performance characteristics and availability to produce power during the most constrained periods of the year; the treatment of each type of resource in the planning reserve margin constraint is discussed below.

6.1.1 CONVENTIONAL

The contribution of thermal generators to resource adequacy is based on the CAISO's Net Qualifying Capacity list. For each type of thermal generation, this list is used to derive an assumed NQC, expressed as a percentage of nameplate capability. For most thermal generation, these percentages are relatively close to 100%. These assumptions are summarized in Table 48.

Table 48. Assumed Net Qualifying Capacity (NQC) for thermal generators (% of maximum capability)

Resource Class	NQC (% of max)
CHP*	100%
Nuclear	99%
CCGT1	95%
CCGT2	98%
Peaker1	98%
Peaker2	98%
Advanced_CCGT	95%

Aero_CT	95%
Reciprocating_Engine	100%
ST	100%

** The NQC of CHP of 100% is a result of the modeling convention used for CHP, in which CHP resources are modeled as baseload resources that produce power at their NQC capacity throughout the year.*

6.1.2 HYDRO

The NQC of existing hydroelectric resources is based on the CAISO's current net qualifying capacity list.

6.1.3 DEMAND RESPONSE

The contribution of demand response resources to the resource adequacy requirement is assumed to be equal to the 1-in-2 ex ante peak load impact. This forecast is discussed in Section 3.5. New flexible loads selected by RESOLVE are not currently assumed to have an impact on the planning reserve margin.

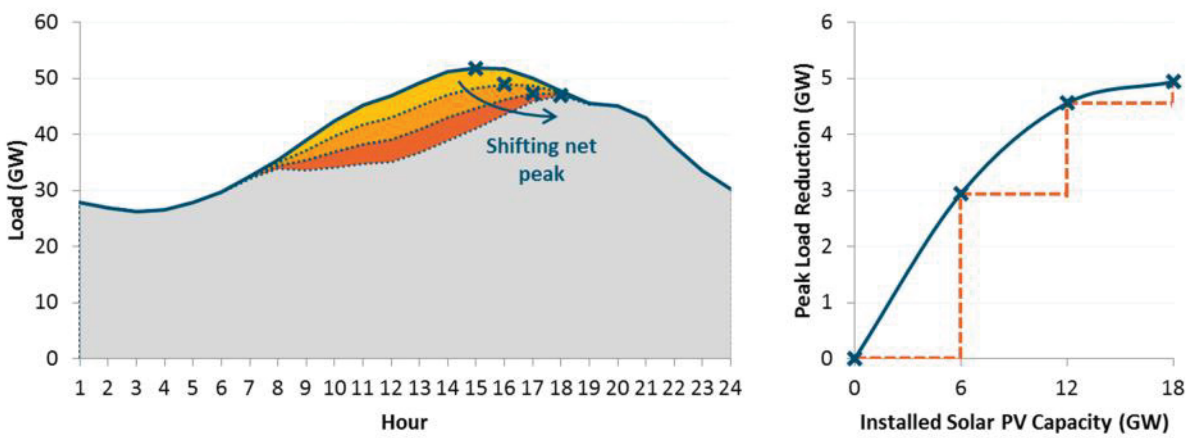
6.1.4 RENEWABLES

Renewable resources with full deliverability capacity status (FCDS) are assumed to contribute to system resource adequacy requirements. Within RESOLVE, these resources fall into two categories: (1) baseload, which includes all biomass, geothermal, and small hydro; and (2) variable resources, which includes both solar and wind resources. The treatment of each category reflects the differences in their intermittency.

For baseload renewables, each resources' contribution to resource adequacy is assumed to be equivalent to its average annual capacity factor (i.e., a geothermal resource with an 80% capacity factor is also assumed to have an 80% net qualifying capacity). This assumption reflects the characteristic of baseload resources that they tend to produce energy throughout the year with a relatively flat profile, and thereby their contribution to peak needs is not materially different from their average levels of production throughout the year.

To measure the contribution of variable renewable resources to system resource adequacy needs, RESOLVE uses the concept of "Effective Load Carrying Capability" (ELCC), defined as the incremental flat load that may be met when that resource is added to a system while preserving the same level of reliability. The contribution of wind and solar PV resources to resource adequacy needs depends not only on the coincidence of the resource with peak loads, but also on the characteristics of the other variable resources on the system as well. This relationship is perhaps best illustrated by the phenomenon of the declining marginal capacity value of solar resources as the “net” peak demand shifts away from periods of peak solar production, as illustrated in Figure 17. Because of this phenomenon, correctly accounting for the capacity contribution of variable renewable resources requires a methodology that accounts for the ELCC of the collective portfolio of intermittent resources on the system.

Figure 17. Illustrative example of the declining ELCC of solar PV with increasing penetration.



To approximate the cumulative ELCC of the CAISO’s wind & solar generators within RESOLVE, RESOLVE incorporates a three-dimensional ELCC surface much like the one derived for the CPUC’s RPS Calculator v.6.0. The surface expresses the total ELCC of a portfolio of wind and solar resources as a function of the penetration of each of those two resources; each point on the surface is the result of a single model run of E3’s Renewable Energy Capacity Planning (RECAP) model. To incorporate the results into RESOLVE, the surface is translated into a multivariable linear piecewise function, in which each facet of the surface is expressed as a linear function of two variables: (1) solar penetration, and (2) wind penetration. The surface is normalized by load, such that the ELCC of a portfolio of resources will adjust with increases or decreases in load.

6.1.5 ENERGY STORAGE

For energy storage, a use-limited resource, the contribution to the planning reserve margin is a function of both the capacity and the duration of the storage device. To align with resource adequacy accounting protocols, RESOLVE assumes a resource with four hours of duration may count its full capacity towards the planning reserve margin. For resources with durations under four hours, the capacity contribution is derated in proportion to the duration relative to a four-hour storage device (e.g. a 2-hour energy storage resource receives half the capacity credit of a 4-hour resource). This logic is applied to all committed and candidate storage resources.

6.1.6 IMPORTS

The contribution of imports to the resource adequacy requirement is based on the CAISO's 2017 allocation of import capability for resource adequacy, which identifies 11,310 MW of import capability available for resource adequacy in CAISO.[23] Because CAISO's contractual shares of both Palo Verde and Hoover are modeled within CAISO in RESOLVE, the capacity of these resources is deducted from the import capability to determine the contribution of imports to the Planning Reserve Margin. These assumptions are shown in Table 49.

Table 49. Assumed import capability for resource adequacy.

	Capacity (MW)
2016 Maximum Import Capability	11,310
Adjustment for CAISO Share of Palo Verde	-622
Adjustment for CAISO Share of Hoover	-797
RESOLVE Import Capacity for Resource Adequacy	**9,891**

6.2 Local Resource Adequacy

RESOLVE also includes a constraint that requires that sufficient new generation capacity must be added to meet the local needs in specific Local Capacity Resource (LCR) areas. To characterize these local capacity needs, RESOLVE relies predominantly on the CAISO's Transmission Planning Process (TPP). Since, in its 2016-'17 TPP, CAISO identified no local areas with expected shortfalls in 2021 or 2026,[24] RESOLVE does not include any local capacity needs in this version.

[23] CAISO, "Step 6 – 2017 Assigned & Unassigned RA Import Capability on Branch Groups." Available at: http://www.caiso.com/Documents/Step6-2017AssignedandUnassignedRAImportCapabilityonBranchGroups.pdf.

[24] CAISO 2016-'17 Transmission Plan, Appendix D: Local Capacity Technical Analysis, available at: https://www.caiso.com/Documents/AppendixD_RevisedDraft_2016-2017TransmissionPlan.pdf

7 Greenhouse Gas Constraint

7.1 Greenhouse Gas Cap

RESOLVE includes optionality to enforce a greenhouse gas constraint on the CAISO generation fleet. The current version of RESOLVE includes a single option for a greenhouse gas constraint, based on CARB's Scoping Plan Alternative 1 scenario. The statewide emissions of the electricity sector in this scenario has been derated to reflect only the CAISO footprint. This target is shown in Table 50.

Table 50. Options for GHG constraints (million metric tons)

Scenario Setting	2018	2022	2026	2030
None	—	—	—	—
Default	59.3	56.5	53.7	50.8
Medium	57.7	52.6	47.6	42.6
Large	56.0	48.8	41.6	34.4
Very Large	54.1	44.2	34.4	24.6

7.2 Greenhouse Gas Accounting

RESOLVE tracks the greenhouse gas emissions attributed to entities within the CAISO footprint using a method consistent with the California Air Resources Board's (CARB) regulation of the electric sector under California's cap & trade program.

7.2.1 CAISO GENERATORS

The annual emissions of generators within the CAISO is calculated in RESOLVE based on (1) the annual fuel consumed by each generator—evaluated endogenously within RESOLVE as part of the dispatch simulation; and (2) an assumed carbon content for the corresponding fuel. Within CAISO, the only fossil fuel consumed by generation resources is natural gas; this fuel is assumed to have a carbon content of 117 lbs per MMBtu.

7.2.2 IMPORTS TO CAISO

RESOLVE also attributes emissions to generation that is imported to CAISO based on the deemed emissions rate for unspecified imports as determined by CARB. The assumed carbon content of imports based on this deemed rate is 0.432 metric tons per MWh—a rate slightly higher than the emissions rate of a combined cycle gas turbine.

The attribution of the deemed rate to imports assumes that imported generation is, in fact, unspecified; in reality, a number of entities outside of California have either specified resources or received asset-controlling supplier status, allowing a lower emissions rate to be applied to power that they schedule to California. Because RESOLVE's dispatch module cannot directly account for these specified and/or portfolio resources, RESOLVE includes an offset to the total emissions to account for the fact that some of the specified generation imported to CAISO will have a lower carbon content than the rate for unspecified power. This amount is equal to 2.8 million metric tons.[25]

[25] This quantity is based on the amount of specified hydro imported to California assumed in CARB's PATHWAYS modeling (8.02 TWh per year), adjusted by the unspecified emissions rate (0.427 tons per MWh) and derated by CAISO's load-ratio share of state load (82%)

Appendix C: Standard LSE Plan Filing Template

There are two different types of templates: the Standard LSE Plan Filing Template and a set of data templates.

1. The Standard LSE Plan Filing Template is reproduced on the following pages. A Word version of the Standard LSE Plan Filing Template is available on the CPUC's website at: http://www.cpuc.ca.gov/irp_proposal.
2. The data templates are in Excel. They are available on the CPUC's website at: http://www.cpuc.ca.gov/irp_proposal.

Energy Division Central Files Document Coversheet

Directions: Submit all documents and submittal questions to Energy Division Central Files via email EnergyDivisionCentralFiles@cpuc.ca.gov

1. Fill out coversheet completely. Coversheet can be embedded as page 1 of the electronic compliance filing, or can be submitted as a separate document that is attached to the email that delivers the compliance filing.
2. All documents are required to be submitted in an electronically *searchable* format.
3. Documents need to reference the reason for the mandate that ordered the filing in Section B or C. If you are unable to reference a proceeding or explain the origin of your filing, please contact Energy Division Central Files.
4. To find a proceeding number (if you only have a decision number), go to http://docs.cpuc.ca.gov/DecisionsSearchForm.aspx; enter the decision number, and the results shown include the proceeding number.

A. Document Name

Today's Date (Date of Submittal) Click here to enter a date.

Name:

1. Utility Name: Click here to enter text.
2. Document Submission Frequency (Annual, Quarterly, Monthly, Weekly, Once, Ad Hoc): Click here to enter text.
3. Report Name: Click here to enter text.
4. Reporting Interval (the date(s) covered by the reported **data**, e.g. 2016 Q4): Click here to enter text.
5. Name Suffix: Cov (for an Energy Division Cover Letter), Conf (for a confidential doc), Ltr (for a letter from utility)
6. Document File Name (format as 1+2 + 3 + 4 + 5): Click here to enter text.

Sample Document Names:
Utility Name + Submittal Frequency + Report Name + Year + Reporting Interval
SCE Annual Procurement Report 2014
SDG&E Ad Hoc DR Exception 2015Q1 Conf
SEMPRA Monthly Gas Report 201602
*SEMPRA Daily Gas Report 201602*30 <no suffix for regular, non-confidential compliance data>
*SEMPRA Daily Gas Report 201602*30 Cov
*SEMPRA Daily Gas Report 201602*30 Ltr <for a cover letter from an Executive>

7. Identify whether this filing is ☐original or ☐revision to a previous filing.
   a. If revision, identify date of the original filing: Click here to enter text.

B. Documents Related to a Proceeding

All submittals should reference both a proceeding and a decision, if applicable. If not applicable, leave blank and fill out Section C.

1. Proceeding Number (starts with R, I, C, A, or P plus 7 numbers): Click here to enter text.

2. Decision Number (starts with D plus 7 numbers): Click here to enter text.
3. Ordering Paragraph (OP) Number from the decision: Click here to enter text.

C. Documents Submitted as Requested by Other Requirements

If the document submitted is in compliance with something other than a proceeding, (e.g. Resolution, Ruling, Staff Letter, Public Utilities Code, or sender's own motion), please explain: Click here to enter text.

D. Document Summary

Provide a Document Summary that explains why this report is being filed with the Energy Division. This information is often contained in the cover letter, introduction, or executive summary, so you may want to copy it from there and paste it here.
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E. Sender Contact Information

1. Sender Name: Click here to enter text.
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F. Confidentiality

1. Is this document confidential? ☐No ☐Yes
   a. If Yes, specify what sections of document are confidential and an explanation of why confidentiality is claimed and identify the expiration of the confidentiality designation (e.g. Confidential until December 31, 2020.) Click here to enter text.

G. CPUC Routing

Energy Division's Director, Edward Randolph, requests that you not copy him on filings sent to Energy Division Central Files. Identify below any Commission staff that were copied on the submittal of this document.

1. Names of Commission staff that sender copied on the submittal of this Document: Click here to enter text.

Standard LSE Plan Template

NAME OF FILING ENTITY

2017 INTEGRATED RESOURCE PLAN

DATE

Table of Contents

1. Executive Summary

Provide an overview of the process used by the LSE to develop its plan and summarize the LSE's findings, including a brief overview of the preferred portfolio identified and proposed next steps.

2. Study Design

Define the specific objectives the LSE intends to achieve with its LSE Plan, the methodology used to develop the LSE Plan, and include documentation of any assumptions used that differ from those used to develop the Reference System Plan.

2.1. Objectives

Provide a description of the LSE's objectives for the analytical work it is documenting in the IRP.

2.2. Methodology

Describe the process by which the LSE developed its IRP, including:

2.2.1. Modeling Tool(s)

Name all modeling software used by LSE to develop its IRP, if any. Include the vendor and version number.

2.2.2. Modeling Approach

As a part of its decision adopting the References System Plan CPUC will require that a certain set of scenarios be evaluated by LSEs, regardless of whether an LSE chooses to use a modeling-based approach to do so. LSEs may also evaluate additional scenarios of interest. Describe the LSE's overall approach to developing the scenarios it evaluated. Explain why each scenario reported in the IRP was considered.

Also describe any calculations (may be post-processing calculations) used to generate metrics for portfolio analysis.

2.2.3. Assumptions

Describe any inputs or assumptions used by the LSE that differs from the corresponding assumption used by the CPUC to prepare the Reference System Plan. Each differing assumption must include a rationale for use of this assumption and any intermediate calculations used to develop the assumption and source data with citations. Include a side-by-side comparison of the original assumption data from the Reference System Plan and the LSE's differing assumption data. Report data according to the requirements in the Data section below.

3. Study Results

3.1. Portfolio Results

Provide an overview of all portfolios produced.

3.2. Preferred Portfolio

Describe the portfolio the LSE prefers to use for planning purposes and for which LSE seeks CPUC approval or certification. Explain the reasons for the LSE's preference and how its preferred plan is consistent with each relevant statutory and administrative requirement. Include the following specific analyses:

3.2.1. Disadvantaged Communities

Describe and provide quantitative evidence to support why the LSE's preferred portfolio is consistent with all statutory requirements and CPUC policy regarding disadvantaged communities.

3.2.2. Cost Analysis

Describe and provide quantitative information to reflect how the LSE anticipates that the LSE's preferred portfolio will affect the costs for the LSE's own ratepayers as well as other ratepayers in CAISO. For this analysis, assume other LSEs procure resources in a manner consistent with the Reference System Plan.

3.2.3. Risk Analysis

Describe the risks to the LSE and the LSE's ratepayers associated with any failures on the part of other LSEs to procure resources consistent with the Reference System Plan. Provide quantitative evidence wherever possible.

3.3. Deviations from Reference System Plan

Describe and quantify any differences between the LSE's preferred plan and the Reference System Plan.

3.4. Deviations from Current Resource Plans

Describe and quantify any differences in the quantities and/or budgets for procurement between the LSE's preferred plan and any currently filed or authorized resource plans, including, but not limited to: Bundled Plans, RPS Plans, Energy Efficiency Business Plans, Distributed Resource Plans, and specific procurement-related applications.

3.5. Local Needs Analysis

LSEs that serve load within a CAISO-defined local capacity area must report the LSE's own assessment of annual incremental local capacity resource needs for the entire local capacity area if it differs from the most recent transmission plan adopted by the CAISO governing board. [1]

4. Action Plan

4.1. Proposed Activities

Describe any near-term activities the LSE proposes to undertake across resource areas in order to implement its IRP. Clearly describe how each activity relates to the study results presented in the previous chapter.

4.2. Barrier Analysis

Identify any market, regulatory, financial, or other barriers or risks associated with the LSE acquiring the resources identified in the preferred portfolio. Include an analysis of how activities of other market actors would affect the proposed activities and what risks those activities pose to the LSE's own ratepayers and to the achievement of state policy goals.

[1] CAISO has ten primary local capacity areas (i.e. transmission-constrained load pocket): Humboldt, North Coast North Bay, Sierra, Stockton, Greater Bay, Greater Fresno, Kern, LA Basin, Big Creek Ventura, San Diego Imperial Valley

4.3. Proposed Commission Direction

Describe any direction that the LSE seeks from the CPUC, including any new spending authorizations, changes to existing authorizations, or changes to existing programmatic goals or budgets. Clearly relate any requested direction to the study results, proposed activities, and barrier analysis presented above.

4.4. Lessons Learned

Document any suggested changes to the IRP process for consideration by the CPUC. Explain how the change would facilitate the ability of the CPUC and LSEs to achieve state policy goals.

5. Common Resource Valuation Methodology

Describe how the LSE plans to value resources in its procurement activities, including bid evaluation in solicitations. Explain how the resource valuation approach takes into account the following:

1. Consistency across all resource types
2. Potential impact of procurement decisions by other LSEs
3. Costs and benefits to and for disadvantaged communities

6. Data

Data shall be reported in the template that will be publicly available on the CPUC website as part of this staff proposal. The template is consistent with the data format that the CPUC will use to specify the Reference System Plan but tailored to allow LSE-specific data reporting. Any supplemental or supporting data incremental to the fields in the data templates shall also be reported, but in separate files. Data reporting must meet the following requirements:

1. For EACH portfolio considered by the LSE, create a file "Data_LSEname_Portfolioname_yyyymmdd.xlsx" using the data template and complete all fields.
    a. The file name must follow the naming format above, where the field "LSEname" is replaced with the LSE name (e.g. "MCE" or "PGE"), the field "Portfolioname" is replaced with the LSE's unique name for the portfolio, and "yyyymmdd" is replaced with the date the file is submitted to the CPUC.
    b. Spaces are not allowed in the file name. Special characters are not allowed, except for underscore ("_") and dash ("-").
    c. The data template includes a worksheet with instructions and multiple worksheets to be filled out by the LSE. The worksheets ask for the following types of information:

i. The portion of the Reference System Portfolio that the LSE intends to use (own or contract with) to serve its assigned load level over the IRP planning horizon. If the resources the LSE intends to use (including new resources that the LSE selected for its portfolio) fall short of the capacity and energy needed to serve LSE load over the IRP planning horizon, it will be assumed that the LSE intends to procure generic capacity and energy on the market.

ii. A list of new resources that the LSE selected for its portfolio. Each resource must be mapped to a RESOLVE resource or portion of a RESOLVE resource the LSE selects to match with or replace.

iii. The LSE's projection of fixed costs from the LSE's existing investments.

iv. The LSE's projection of fixed costs from the list of new resources that the LSE selected for its portfolio, including fixed costs from any new transmission necessitated by the LSE's selected new resources .

v. The LSE's annual peak load and average energy forecast including any impacts from load modifying resources.

d. Each worksheet includes data validation that requires the LSE to populate cells with only allowed values.

e. Cells must contain only text or numerical data. Any comments about certain cells or rows shall be made in the text body of the primary LSE Plan report, not in the data template.

2. In rare instances, the LSE may need to report supplemental or supporting data incremental to the fields in the data template described above. An example is where the LSE used a set of assumptions to develop a portfolio that differs from the corresponding set of assumptions used to develop the Reference System Plan, and those assumption differences are not captured in the required data template above. The requirement to report assumptions differences was stated above as required content for the "Study Design" section of an LSE Plan. The numerical data for such differences shall be reported in separate Excel-compatible workbooks and follow these requirements:

   a. For EACH portfolio considered by the LSE that requires supplemental or supporting data, report the data in a file "Diff_LSEname_Portfolioname_yyyymmdd.xlsx" and follow the same file naming convention described above for the data template file.

   b. For each differing assumption include a side-by-side comparison of the original assumption data from the Reference System Plan and the LSE's differing assumption data.

   c. Explanations for each difference shall be made in the text body of the primary LSE Plan report, not the Excel workbook.

Appendix D: Reference System Portfolio Data Files

The following list itemizes the data files that the CPUC will provide to specify the Reference System Portfolio. Of the items listed below, only the RESOLVE_Scenario_Tool is currently available for public review and comment. The other two items will be released when the Reference System Plan is released.

1. RESOLVE_Scenario_Tool: This is a large Excel-macro-enabled workbook capturing every input assumption choice used in the RESOLVE model. This Tool is included with this staff proposal and may be used to examine every input assumption that RESOLVE may use. The Tool contents are described in the companion "RESOLVE Inputs and Assumptions" document provided in conjunction with this staff proposal. However, the RESOLVE capacity expansion model functionality is disabled. The model will be enabled when the Reference System Plan is released.
2. RESOLVE_Results_Tool: This is an Excel-macro-enabled workbook used to display RESOLVE model results. This Tool will not be available until the Reference System Plan is released. It contains summary metrics (e.g. total new build by type and year, total fixed and operating costs, total emissions) and detailed portfolio data. Paired with this workbook are sets of comma-separated-values format text files describing each portfolio produced by the RESOLVE model. These files are the raw output of the RESOLVE model.
3. Production cost modeling .csv files: These are comma-separated-values format text files that describe portfolio data in a format that can more readily be imported into commercial analytical tools such as production cost simulation models and databases. They are generated by the RESOLVE model. These files delineate the Baseline Inventory of all existing physical resources and planned resources (those with committed/approved contracts), aggregated by RESOLVE resource type, plus the inventory of new resources selected by RESOLVE.